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16. Abstract (Limit: 200 words)

This document provides a broad view of three major coal conversion technologies: coal liquefaction, surface, and in situ coal gasification for use as background material for participants in the Interagency Workshop on the Health and Environmental Effects of Coal Gasification and Liquefaction Technologies. Information is included on coal technologies, including specific process options considered likely candidates for commercialization. Detailed information is presented on process steps and associated waste streams and potential constituents. Process description and diagrams for selected technology processes are also provided. Precautionary considerations and the state of knowledge are given for all waste streams including water effluents, air emissions, and solid wastes. This information provides a sound basis for source characterization. Descriptions of classes of potential pollutants associated with waste streams include seven categories of pollutants possibly associated with coal conversion technologies: air, water, solids, organics, trace elements, transients, and products and by-products.

A discussion of potential health and environmental problems of the technologies provides a "strawman" set of potential problems. These problems were a starting point from which the workshop panelist could identify and establish research priorities for the entire energy cycle.

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Edited by:
James Antizzo

July 1978

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PURPOSE

The purpose of this document is to provide background material for participants in the Interagency Workshop on the Health and Environmental Effects of Coal Gasification and Liquefaction technologies. The workshop is jointly sponsored by the Department of Energy, the Department of Health, Education and Welfare and the Environmental Protection Agency. The document is an edited compilation of information designed to provide a broad view of three major coal conversion technologies: coal liquefaction, coal gasification, and in situ gasification.

The document is organized to provide several different cuts of information, depending upon the needs of individual users. It consists of five major sections and four Appendices containing supporting material.

The introduction provides a brief overview of the need for coal conversion technology, and a short description of coal resources available for conversion. The primary purpose of the discussion of coal resources is to make the reader aware of the great variations in chemical and physical properties of coal and subsequent variations in environmental implications.

Section 2 provides brief, generic descriptions of the three technologies, including technology classifications and status, process chemistry, and process sequences. Specific process options which are considered likely candidates for emphasis and commercialization are indicated.

Section 3, Source Characterization, provides an overview of potential sources of pollutant streams, and the general classes of pollutants which may be present in those streams. The section also discusses the various perspectives from which source characterization may be accomplished, and the general problems associated with comparability of results. Finally, section 3 presents the state of knowledge of source characterization for the three technologies. More detailed descriptions of process steps which may be used in the three technologies are presented in Appendix A. The Appendix also identifies potential waste streams associated with each process step, possible constituents of the streams, and a brief discussion of the most salient environmental aspects. Appendix B provides more detailed process descriptions, flow diagrams and development schedules for specific process options, e.g., Solvent Refined Coal, Hygas, Bi-gas.

Section 4, Potential Pollutants, is a discussion of the pollutants which may be associated with coal conversion technologies. The pollutants are discussed in seven categories: air, water, solids, organics, trace elements, products and by-products, and transients.

Qualitative and quantitative data are presented in Section 4 and in Appendix C to provide an indication of the species and concentrations which have been found in various studies. But again the reader is cautioned that the data may not be truly representative or scalable to commercial facilities; considerable source characterization work remains to be done.

Appendix D is a cursory description of legislation which may affect efforts to develop and commercialize coal conversion technologies.

Section 5 presents a discussion of potential health and environmental problems of the technologies. The purpose of this section is to provide a "strawman" set of potential problems for each of the five panels of the workshop. A significant activity for each panel at the workshop will be the identification and prioritization of potential health and environmental problems, for the entire energy cycle, of each technology. The "strawman" problems presented here are to be considered only a starting point and are offered to panelists for augmentation and modification.

TABLE OF CONTENTS

Page
LIST OF TABLES ix
LIST OF ILLUSTRATIONS xi

1.0 INTRODUCTION

1.1 Overview 1
1.2 Coal Resource 4

2.0 TECHNOLOGY DESCRIPTION

2.1 Coal Gasification 13
2.1.1 Introduction 13
2.1.2 Technology Classification and Status 13
2.1.3 Process Chemistry 15
2.1.4 Gasification Sequence 15
2.2 Coal Liquefaction 17
2.2.1 Introduction 17
2.2.2 Technology Status 18
2.2.3 Process Chemistry 21
2.2.4 Liquefaction Sequence 22
2.3 In Situ Gasification 22
2.3.1 Introduction 22
2.3.2 Technology Status 26
2.3.3 Process Chemistry 27
2.3.4 In Situ Gasification Sequence 28

3.0 SOURCE CHARACTERIZATION

3.1 Introduction 29
3.2 Precautionary Considerations 32
3.3 State of Knowledge 33

4.0 POTENTIAL POLLUTANTS

4.1 Introduction 41
4.2 Air 42
4.3 Water 49
4.4 Solids 51
4.5 Organics 62
4.6 Trace Elements 64
4.7 Products and By-products 72
4.8 Transient Pollutants 75

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TABLE OF CONTENTS (Concluded)

5.0 STRAWMAN PROBLEMS — Page

5.1 Examples of Health Effects Associated with Coal Conversion 81

5.1.1 Introduction 81
5.1.2 Emissions 84
5.1.3 Epidemiology 87
5.1.4 Areas Where Research is Needed 88
5.1.5 Safety and Occupation Risks 90

5.2 Characterization Measurement and Monitoring 91

5.2.1 Introduction 91

5.3 Aquatic Concerns 94

5.3.1 Introduction 94
5.3.2 Gasification and Liquefaction 95

5.4 The Effect of Coal Conversion on Air Quality 98

5.4.1 Introduction 98
5.4.2 Transport and Diffusion 99
5.4.3 Chemical and Physical Transformation 100
5.4.4 Local Atmospheric Transformations 101
5.4.5 Site Specific Features 102
5.4.6 Conclusions 103

5.5 Terrestrial Concerns 104

5.5.1 Introduction 104

APPENDIX A - Process Steps and Associated Waste Streams and Potential Constituents 109

APPENDIX B - Process Description and Diagrams for Selected Technology Processes 149

APPENDIX C - Potential Pollutants of Concern 209

APPENDIX D - Legislation Applicable to Coal Conversion Facilities 248

BIBLIOGRAPHY 253

LIST OF TABLES

Table Number Page

1-1 Applicability and Status of Coal Conversion Technologies 3
1-2 Classification of Coals by Rank (ASTM D 388) 5
1-3 Distribution of Coals by Provice in the United States 7
1-4 Mean Analytical Values for 101 Bituminous Coals 8

2-1 Technology Status of Coal Gasification Process 14
2-2 Coal Liquefaction Processes 19

3-1 Potential for Fugitive Emissions from Advanced Coal Process Module 31
3-2 Relative Advantages and Disadvantages of Process Variable/Effluent Experiments at Various Scales 34
3-3 Comparison of CO_2 Acceptor Pilot-Plant and Full-Scale-Plant Waste Streams 35
3-4 Sampling Efforts 36
3-5 Available Information on Emissions From Coal Gasification Processes 39
3-6 Available Information on Emissions from Coal Liquefaction Processes 40

4-1 Components in Gasifier Gas, PPM 44
4-2 Estimates of Sulfur Recovery and Discharges for the Bi-Gas and SRC Processes 46
4-3 Estimates of Ammonia and Hydrogen Cyanide From Coal Refining 47
4-4 Yearly Estimated Emissions (Tons/Year) From WESCO Coal Gasification (Lurgi) Plant with Pollution Control 50
4-5 Coal Tar Constituents by Boiling Point 52
4-6 Ash and Char Generation in Gasifiers 54
4-7 Estimates of Slag, Char, and Ash Discharges, Bi-Gas and SRC Processes 55
4-8 Characteristics of Coal Pile Drainage 57
4-9 Minor Trace Elements 58
4-10 Range in Amount of Trace Elements Present in Coal Ashes 59
4-11 Elements Exceeding Recommended Water Quality Levels 61
4-12 Mean Analytical Values for 101 Coals 66
4-13 Trace Element Content of American Coals 67

LIST OF TABLES (Concluded)

Table Number		Page
4-14	Distribution of Environmentally Hazardous Trace Elements	67
4-15	Trace Element Concentration of Pittsburgh No. 8 Bituminous Coal at Various Stages of Gasification	70
4-16	Potentially Hazardous Trace Elements	70
4-17	Trace Element Results (PPM) for the COED Process	71
4-18	Inspection of Products from Illinois No. 6 Coal	73
4-19	Quantities of PAH in a Coal-Derived Liquefaction Product	76
4-20	PAH Compounds in Synthoil	76
4-21	PAH in COED Samples	76
4-22	Organic Sulfur Compounds in the Products of Coal Hydrogeneration	77
4-23	Possible Sources of Transient Pollutants	79

LIST OF ILLUSTRATIONS

Figure Number		Page
1-1	Coal Fields of the Conterminous United States	6
1-2	Proposed Structure of a High Volatile Bituminous Coal	9
1-3	Periodic Table of the Elements	11
2-1	Schematic Flow Diagram of a Coal Gasification Plant	16
2-2	Coal Liquefaction Routes	20
2-3	Generalized Coal Liquefaction Scheme	23
2-4	Coal Fields of the United States	24
2-5	Underground Coal Gasification Production and End Uses	25
3-1	Emission Fates for Coal Conversion Process	30
4-1	Periodic Table of the Elements	65

1.0 INTRODUCTION

1.1 OVERVIEW

The growing divergence between the demand for liquid and gaseous fuels in the United States and domestic supply necessitates a strong, balanced energy program to develop alternative fuel sources.

Fortunately, U.S. coal reserves are estimated to amount to more than 80 percent of the total of coal, oil, and gas that is available and are sufficient to support production of a large amount of synthetic fuels. The 230 billion tons of coal that are considered minable by existing methods on a reasonably economic basis, could supply the country's estimated requirements for solid, liquid and gaseous fuels for decades.

Coal conversion consists of essentially two basic steps: the cracking of heavy hydrocarbons into lighter ones and the enrichment of the resultant molecules with hydrogen. It may be accomplished either underground (in situ) or by mining coal and transferring it to surface conversion plants. And it may produce either a liquid (liquefaction) or a gas (gasification), in addition to by-products.

Although coal conversion may be a relatively simple concept, development and commercialization of an economically viable industry will require overcoming significant technical and environmental obstacles. One of the outstanding features of any future commercial coal conversion facility will be its size. A standard 250 million SCFD gasification plant or 50,000 BPD liquefaction plant will process 15,000 to 25,000 tons of coal per day, often at high temperatures and pressures (greater than 1000°F and 3500 psi). It may require opening a large new surface mine or two large underground mines. It will require containment and control of highly corrosive and potentially harmful process materials, in large reaction vessels, perhaps exceeding 200 feet in height and weighing more than 1500 tons. It will require treatment and disposal of voluminous solid waste and will consume water equivalent to the flow of a small river. The complex may employ 4,000 people. Including coal storage piles and water treatment ponds, the facility may require more than a square mile of land. The plant, mine and new residences may affect up to 200 square miles. New roads, power lines and pipe lines may affect additional areas. The total cost of the facility will exceed $1 billion. Yet in terms of energy production, a single commercial plant is relatively small. Its energy output is approximately equivalent to 0.4 percent of our material gas production. (43,57).*

The national benefits of coal conversion plants will be many and important. The plants will provide a critically needed supplement to our dwindling oil and gas reserves. The synthetic oil and gas produced will be environmentally compatible and clean burning. The products will be both storable and transportable, and synthetic oil and gas will make us less dependent on unstable and costly foreign suppliers, thus improving our balance of payments and increasing national security.

However, to secure these long-term national benefits, great care must be taken to avoid potential negative impacts on social, natural, and environmental resources.

The magnitude of future commercial production by coal conversion can only be subject to reasonable guesses due to its dependence on a variety of variables, including availability of substitutes, government policy, economics and environmental factors. However a production rate of 1.4 billion cubic feet per day of gas (natural gas equivalent) and 100,000 barrels per day of liquid hydrocarbons (crude oil equivalent) has been estimated for 1985. Projections for the year 2000 are 8 billion cubic feet per day of gas and 1,000,000 barrels per day of liquids (102).

The applicability and status of coal conversion technologies are presented in Table 1-1.

---

*Numbers in parentheses refer to reference numbers in bibliography.

TABLE 1-1

APPLICABILITY AND STATUS OF COAL CONVERSION TECHNOLOGIES

Pollutants and Control Technology	Pollutant Reduction Efficiency %	Time Frame of Applicability		
		Utility	Industrial	Residential and Commercial
Coal Gasification				
Low BTU	90-95	Post-1980 (More applicable to new units)	Applicable Only to Largest Units	Not Applicable
High BTU	90-95	Post-1980 (New and existing units) (high costs)	Post-1980 (Widely applicable) (high costs)	Post-1980 (Widely applicable) (high costs)
Coal Liquefaction	90-95	Post-1985 (New and existing units)	Post-1985	Under Evaluation

(SOURCE: Adapted from reference 45)

1.2 COAL RESOURCE

An understanding of the structure, composition and distribution of coal is essential if coal conversion processes are to be analyzed and potential environmental problems identified.

Coal is a carbonaecous, nonhomogeneous, highly variable fossilized material derived from decayed plant material. This decayed material (peat) was subjected to a variety of microbiological, geophysical, and geochemical conditions; quantitative statements concerning the composition, structure, and products of coal therefore are subject to variation.

Coal is classified by rank according to volatile matter and heat content (Btu/lb). In general, carbon content increases and volatile matter decreases with increase in rank, while oxygen content correlates with decreasing rank. Rank varies sequentially from the low-rank lignite through sub-bituminous and bituminous to high-rank anthracite. The American Society for Testing and Materials (ASTM) classification of coals by rank is shown in Table 1-2. Distribution of coals is presented in Figure 1-1 and Table 1-3. (15).

Due to its origin coal is a highly variable material, as illustrated by the values for 101 bituminous coals shown in Table 1-4. Thus the products of any given coal in any given reaction will differ from those of another coal under similar circumstances. Despite the extreme variability, it is possible to generalize about coal and coal reactions, providing that the limitations are kept in mind. A good general discussion of coal is provided in Richmond, et. al:

> "Theories of coal structure produce models such as that in Fig. 1-2. This diagram shows high volatile bituminous coal (an intermediate classification) as being composed of aromatic clusters, linked into huge molecules by carbon bridges and by hetero-atom groups like OH, CO, COOH, NH_2, CN, S, and SH. Ignoring water and ash content (a moisture - and ash-free or maf basis), organic matter normally can be 70-90% carbon, 2-6% hydrogen, 1-2% nitrogen, 0.5-6% sulfur, and 2-20% oxygen (by weight). Moisture content of freshly mined coal will depend on

TABLE 1-2

CLASSIFICATION OF COALS BY RANK (ASTM D 388)

Group	Fixed carbon limits[b] (%)		Volatile matter limits[b] (%)		Calorific value limits[c] (Btu/lb)		Agglomerating character
	Equal or greater than	Less than	Greater than	Equal or less than	Equal or greater than	Less than	
			Anthracite				
Metaanthracite	98			2			Nonagglomerating
Anthracite	92	98	2	8			
Semianthracite[d]	86	92	8	14			
			Bituminous				
Low-volatile bituminous	78	86	14	22			Commonly agglomerating[f]
Medium-volatile bituminous	69	78	22	31			
High-volatile A bituminous		69	31		14,000[e]		
High-volatile B bituminous					13,000[e]	14,000	
High-volatile C bituminous					11,500	13,000	
					10,500[d]	11,500	Agglomerating
			Subbituminous				
Subbituminous A					10,500	11,500	Nonagglomerating
Subbituminous B					9,500	10,500	
Subbituminous C					8,300	9,500	
			Lignite				
Lignite A					6,300	8,300	
Lignite B						6,300	

---

[a] This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high-volatile bituminous and subbituminous ranks. All of these coals either contain less than 48% dry, mineral-matter-free fixed carbon or have more than 15,500 moist, mineral-matter-free Btu/lb.

[b] Dry, mineral-matter-free basis.

[c] Moist, mineral-matter-free basis; moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[d] If agglomerating, classify in low-volatile group of the bituminous class.

[e] Coals having 69% or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

[f] It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high-volatile C bituminous group.

(SOURCE: 15, pp. 2-12)

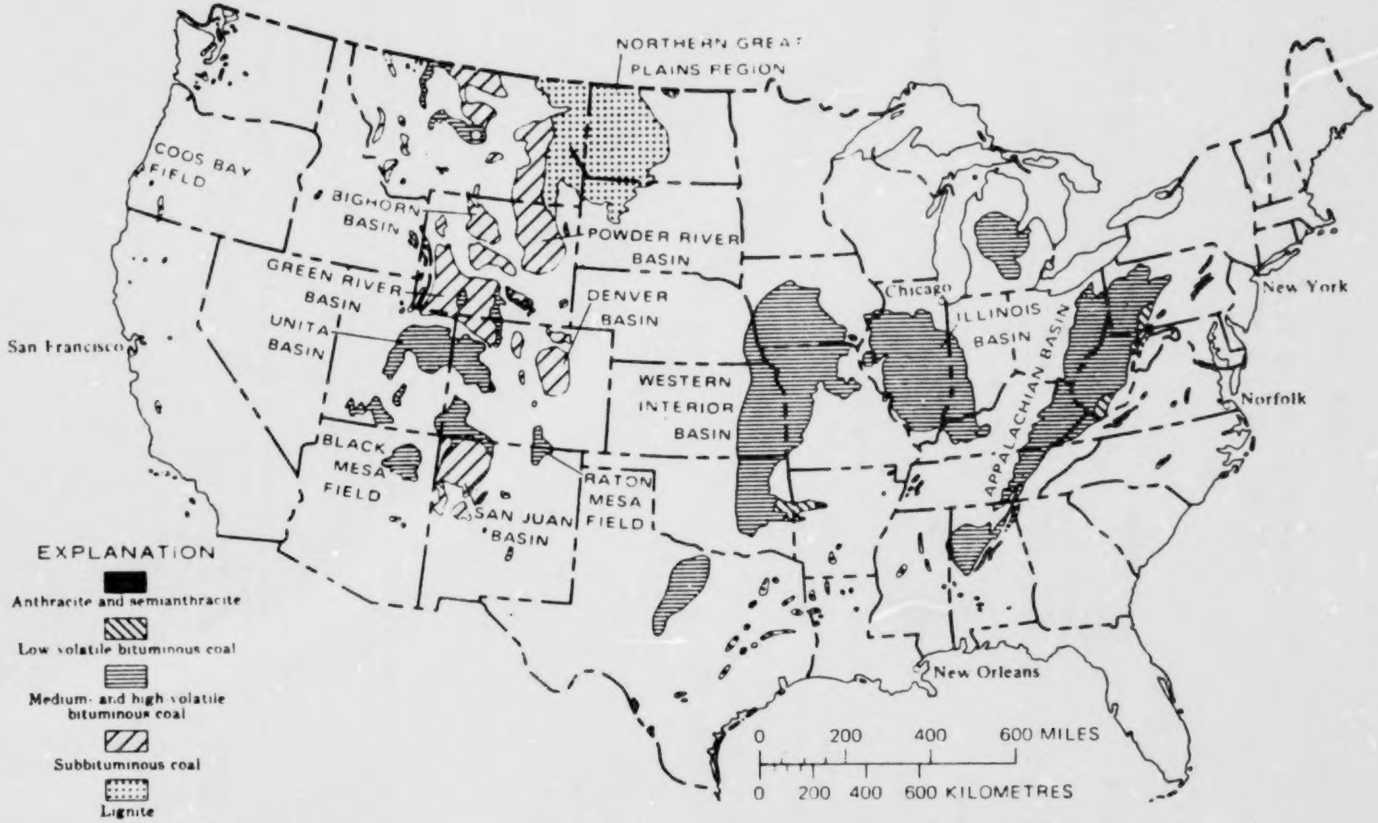

NORTHERN GREAT PLAINS REGION
COOS BAY FIELD
BIGHORN BASIN
POWDER RIVER BASIN
GREEN RIVER BASIN
DENVER BASIN
UNITA BASIN
WESTERN INTERIOR BASIN
BLACK MESA FIELD
RATON MESA FIELD
SAN JUAN BASIN
ILLINOIS BASIN
APPALACHIAN BASIN
Chicago
New York
Norfolk
New Orleans
San Francisco
EXPLANATION
Anthracite and semianthracite
Low volatile bituminous coal
Medium- and high volatile bituminous coal
Subbituminous coal
Lignite
0 200 400 600 MILES
0 200 400 600 KILOMETRES

FIGURE 1-1. COAL FIELDS OF THE CONTERMINOUS UNITED STATES

(SOURCE: 9, p. 5)

TABLE 1-3

DISTRIBUTION OF COALS BY PROVINCE IN THE UNITED STATES

	Appalachian	Interior	North Great Plains	Rocky Mountain	Pacific	Gulf	Alaska
States	Pennsylvania, Ohio, Virginia, West Virginia, E. Kentucky, Alabama, Tennessee	East coal region Indiana, Illinois, W. Kentucky West coal region Oklahoma, Missouri, Kansas, Arkansas	N and S Dakota, Montana, NE Wyoming	Many distinct basins of different geological history in SW Wyoming, Colorado, Utah, New Mexico, Arizona	Washington, Oregon, California	Parts of Arkansas, Texas, Louisiana, Mississippi, W Alabama	Alaska
Age, million years	Carboniferous (300)	Carboniferous	Some Cretaceous, mostly early Tertiary (100 - 50)	Mostly Cretaceous, some early Tertiary (130 - 60)	Tertiary (60 - 15)	Tertiary (70 - 30)	Cretaceous and early Tertiary (100 - 50)
ASTM rank	Principal deposits of high-volatile A and B, medium-volatile, and low-volatile bituminous, anthracite	Principal deposits of subbituminous, high-volatile A, B, and C; minor deposits of low-volatile bituminous and anthracite	Principal deposits of lignite and subbituminous	Principal deposits of subbituminous and high-volatile A, B, and C bituminous; minor deposits of medium-volatile bituminous and anthracite	Principal deposits of lignite, subbituminous and high-volatile A, B, and C bituminous; minor deposits of anthracite	Principal deposits of lignite	Principal deposits of subbituminous and high-volatile A, B, and C bituminous

(SOURCE: 15, p. 2-15)

TABLE 1-4

MEAN ANALYTICAL VALUES FOR 101 BITUMINOUS COALS

Constituent	Mean	Standard Deviation	Minimum	Maximum
Arsenic	14.02 ppm	17.70	0.50	93.00
Boron	102.21 ppm	54.65	5.00	224.00
Beryllium	1.61 ppm	0.82	0.20	4.00
Bromine	15.42 ppm	5.92	4.00	52.00
Cadmium	2.52 ppm	7.60	0.10	65.00
Cobalt	9.57 ppm	7.26	1.00	43.00
Chromium	13.75 ppm	7.26	4.00	54.00
Copper	15.16 ppm	8.12	5.00	61.00
Fluorine	60.94 ppm	20.99	25.00	143.00
Gallium	3.12 ppm	1.06	1.10	7.50
Germanium	6.59 ppm	6.71	1.00	43.00
Mercury	0.20 ppm	0.20	0.02	1.60
Manganese	49.40 ppm	40.15	6.00	181.00
Molybdenum	7.54 ppm	5.96	1.00	30.00
Nickel	21.07 ppm	12.35	3.00	80.00
Palladium	71.10 ppm	72.81	5.00	400.00
Lead	34.78 ppm	43.69	4.00	218.00
Antimony	1.26 ppm	1.32	0.20	8.90
Selenium	2.08 ppm	1.10	0.45	7.70
Tin	4.79 ppm	6.15	1.00	51.00
Vanadium	32.71 ppm	12.03	11.00	78.00
Zinc	272.29 ppm	694.23	6.00	5,350.00
Zirconium	72.46 ppm	57.78	8.00	133.00
Aluminum	1.29 %	0.45	0.43	3.04
Calcium	0.77 %	0.55	0.05	2.67
Chlorine	0.14 %	0.14	0.01	0.54
Iron	1.92 %	0.79	0.34	4.32
Potassium	0.16 %	0.06	0.02	0.43
Magnesium	0.05 %	0.04	0.01	0.25
Sodium	0.05 %	0.04	0.00	0.20
Silicon	2.49 %	0.80	0.58	6.09
Titanium	0.07 %	0.02	0.02	0.15
Organic Sulfur	1.41 %	0.65	0.31	3.09
Pyritic Sulfur	1.76 %	0.86	0.06	3.78
Sulfate Sulfur	0.10 %	0.19	0.01	1.06
Total Sulfur	3.27 %	1.35	0.42	6.47
Moisture	9.05 %	5.05	0.01	20.70
Volatile Matter	39.70 %	4.27	18.90	52.70
Fixed Carbon	48.82 %	4.95	34.60	65.40
Ash	11.44 %	2.89	2.20	25.80
Btu/lb	12,748	464.50	11,562.00	14,362.00
Carbon	70.28 %	3.87	55.23	80.14
Hydrogen	4.95 %	0.31	4.03	5.79
Nitrogen	1.30 %	0.22	0.78	1.84
Oxygen	8.68 %	2.44	4.15	16.03
High-Temperature Ash	11.41 %	2.95	3.28	25.85
Low-Temperature Ash	15.28 %	4.04	3.82	31.70

(SOURCE: 105, p. 18)

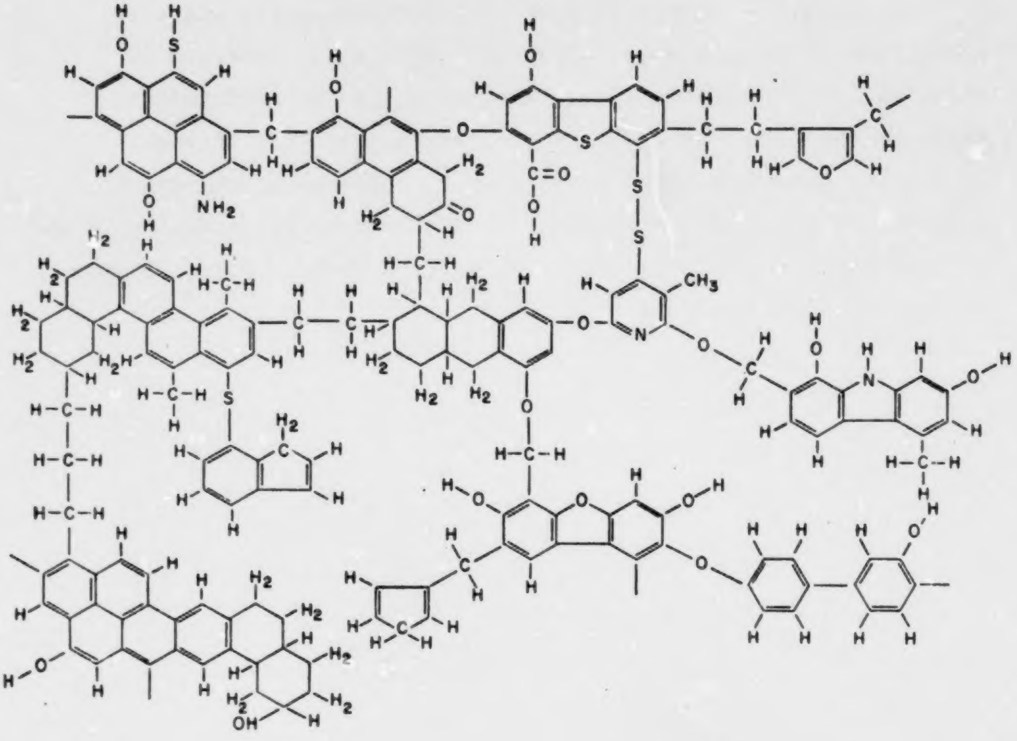


FIGURE 1-2

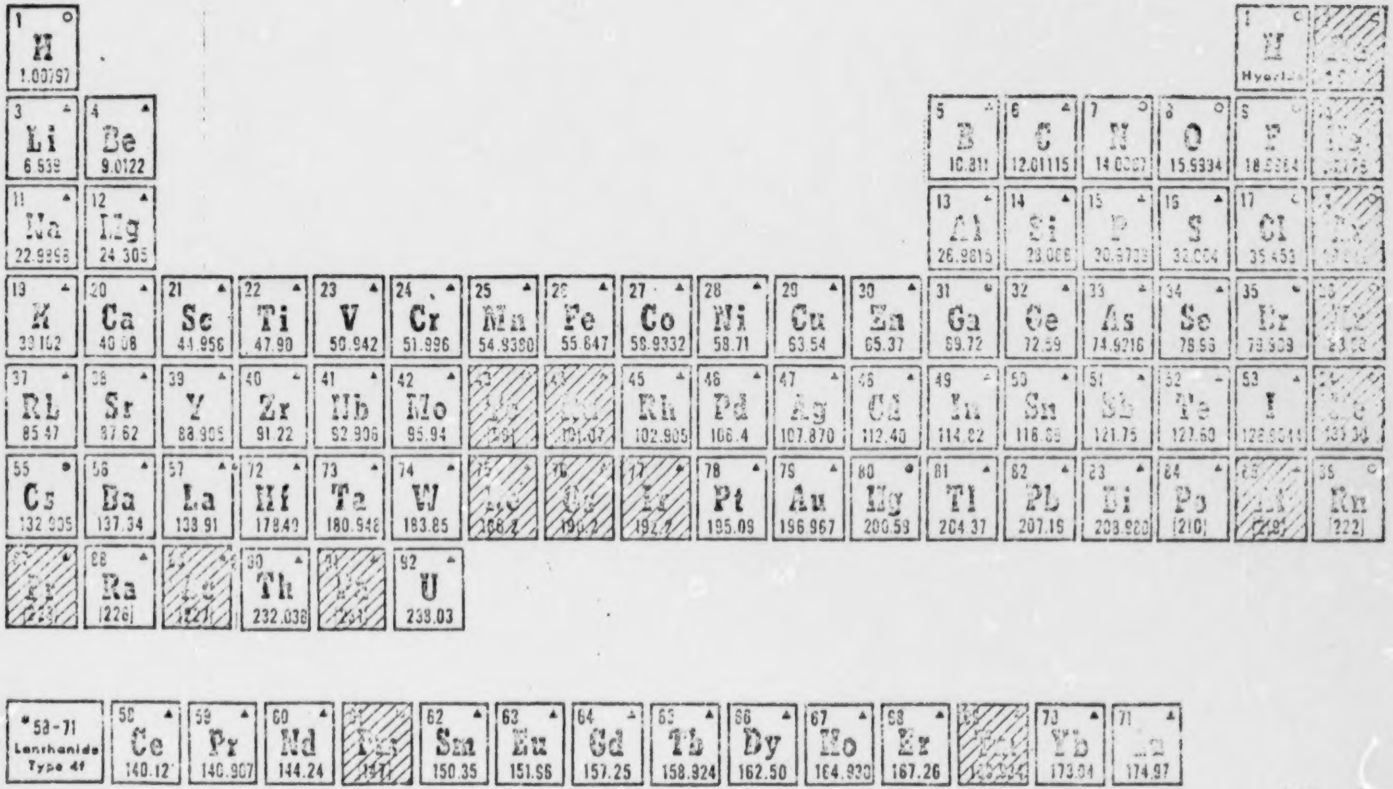
PROPOSED STRUCTURE OF A HIGH VOLATILE BITUMINOUS COAL

(SOURCE: 118)

> ground water, but changes due to transport from minemouth to consumption site, open storage, and precreatment vary widely. Inorganic matter is measured as ash, normally ranging from 3-30%. Ash is primarily oxides of silicon, aluminum, iron, and calcium but also has important amounts of FeS_2, $FeSO_4$, $CaSO_4$, and trace elements."(102).

Trace elements found in coal are presented in Figure 1-3.

The essential nature of many coal conversion processes is production of hydrocarbons, which are enriched in hydrogen as compared to the original coal. Enrichment can be performed by removing the volatile, hydrogen-rich organic content through pyrolysis, leaving a high-carbon char or coke; by adding extra hydrogen to the carbon contained in the coal; or by producing CO and H_2 from the coal and catalytically reacting the molecules to form CH_4 and/or higher hydrocarbons (102).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12 Mg 24.305
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20 Ca 40.08
21 Sc 44.956
22 Ti 47.90
23 V 50.942
24 Cr 51.996
25 Mn 54.9380
26 Fe 55.847
27 Co 58.9332
28 Ni 58.71
29 Cu 63.54
30 Zn 65.37
37 Rb 85.47
38 Sr 87.62
39 Y 88.905
40 Zr 91.22
41 Nb 92.906
42 Mo 95.94
45 Rh 102.905
46 Pd 106.4
47 Ag 107.870
48 Cd 112.40
55 Cs 132.905
56 Ba 137.34
57 La 138.91
72 Hf 178.49
73 Ta 180.948
74 W 183.85
78 Pt 195.09
79 Au 196.967
80 Hg 200.59
88 Ra [226]
90 Th 232.038
92 U 238.03
1 H Hydrogen
5 B 10.811
6 C 12.01115
7 N 14.0067
8 O 15.9994
9 F 18.9984
13 Al 26.9815
14 Si 28.086
15 P 30.9738
16 S 32.064
17 Cl 35.453
31 Ga 69.72
32 Ge 72.59
33 As 74.9216
34 Se 78.96
35 Br 79.909
49 In 114.82
50 Sn 118.69
51 Sb 121.75
52 Te 127.60
53 I 126.9044
81 Tl 204.37
82 Pb 207.19
83 Bi 208.980
84 Po [210]
86 Rn [222]
*58-71 Lanthanide Type 4f
58 Ce 140.12
59 Pr 140.907
60 Nd 144.24
62 Sm 150.35
63 Eu 151.96
64 Gd 157.25
65 Tb 158.924
66 Dy 162.50
67 Ho 164.930
68 Er 167.26
70 Yb 173.04
71 Lu 174.97

(SOURCE: 86, p. 419)

FIGURE 1-3

PERIODIC TABLE OF THE ELEMENTS

2.0 TECHNOLOGY DESCRIPTIONS

2.1 COAL GASIFICATION

2.1.1 Introduction

Gasification of coal transforms a cumbersome, inconvenient, dirty solid fuel into a convenient, clean, gaseous fuel, or into synthesis gas (a mixture of carbon monoxide and hydrogen).

2.1.2 Technology Classification and Status

Gasification processes may be classified into three categories, depending upon the heating values of the product gases:

Low-Btu gas (100-200 Btu/scf) options which use an air-steam mixture to gasify the coal. Low-Btu gas is suitable for use as an energy source near its point of generation, but, because of its low Btu content, it is not economically attractive for long distance transmission.

Medium-Btu gas or synthesis gas (500 Btu/scf) options which use an oxygen-steam mixture to gasify the coal. Medium-Btu gas can be used either as an energy source or as a synthesis gas for the production of chemicals and synthetic liquid and gaseous fuels.

Synthetic pipeline gas (1000 Btu/scf), indistinguishable from natural gas, is produced by further processing of intermediate-Btu gas. The required processing includes removal of particulate matter and condensables, adjustment of the gas composition by converting CO and H_2O to H_2 and CO_2 (shift conversion), removal of H_2S, and CO_2, and methanation of the resulting gas mixture (102).

Gasification processes may also be classified according to gasifier characteristics such as dry-ash moving bed, slagging moving bed, dry-ash fluid bed, ash agglomerating fluid bed, entrainment, slagging entrainment, and molten bath. These characteristics will be discussed later.

The status of coal gasification processes is presented in Table 2-1.

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TABLE 2-1

TECHNOLOGY STATUS OF COAL GASIFICATION PROCESSES

Process (developer)	Product gas Btu content	Reactor bed type	Number of stages	Pressure/temperature (atm/°C)	Current capacity (t/d)	Possible commercialization
Commercial						
Koppers-Totzek (Koppers GmbH)	Medium	Entrained	1	1/950-2150	850	Available now
Lurgi (Lurgi Mineraloltechnik GmbH)	Medium	Moving	1	20-30/600-750	1000	Available now
Wellman-Galusha (McDowell-Wellman)	Medium	Moving	1	1/600	100	Available now
Winkler (Davy Powergas)	Medium or low	Fluidized	1	1-3/800-1000	1500	Available now
Demonstration						
Lurgi - using agglomerating coals	Low	Moving (stirred)	1	20/500	2000	By 1985
Pilot Plant						
BI-GAS (Bituminous Coal Research)	Medium	Entrained	2	70-100/900-1500	120	By 1985
Cogas (FMC)	Medium	Fluidized	1	2-4/900	53 (char)	Near 1985
CO_2 Acceptor (Consolidated Coal)	Medium	Fluidized	2	10-20/900	40	Near 1985
HYGAS (Institute of Gas Technology)	Medium	Fluidized	2	70-100/700-1000	80	By 1985
SYNTHANE (Pittsburgh Energy Res. Ctr.)	Medium	Fluidized	1	40-70/900	75	By 1985
Union Carbide/Battelle	Medium	Fluidized	1	7/1000	25 (U.C.)	Near 1985
Stirred fixed-bed producer (Morgantown Energy Res. Ctr.)	Low	Moving	1	20/550	20	Near 1985
Combustion Engineering/ Consolidated Edison	Low	Entrained	1	1-10/1150+	120	After 1985
Westinghouse	Low	Fluidized	2	10-16/900-1000 and 1150	14	Near 1985
Pittsburg & Midway Coal Mining	Low	Entrained	2	4-35/1150+	30	Near 1985
U-Gas (Institute of Gas Technology)	Low	Fluidized	1	20/1050	30	After 1985
Laramie Energy Research Center	Low	Underground (in situ)	1	10/?	13-46	Near 1985

(SOURCE: 102, p. 9)

2.1.3 Process Chemistry

Gasification of coal entails the treatment of coal in a reducing atmosphere with air, oxygen, steam, CO_2, or hydrogen or mixtures of these gases, to yield a combustible product. The product of primary gasification of coal and of the reaction of coal carbon with the gasifying agent is usually a mixture of H_2, H_2O, CO, CO_2, CH_4, inerts and minor amounts of hydrocarbons and other impurities (51).

2.1.4 Gasification Sequence

A "typical" gasification plant is difficult to define as too many variables exist, e.g., process options, coal feedstock, gasifier operational mode, and purification processes. However, similarities do exist in the basic processing steps.

Figure 2-1 is a general flow plan for coal gasification. Not all the units are the same for different processes and for some, additional units are required.

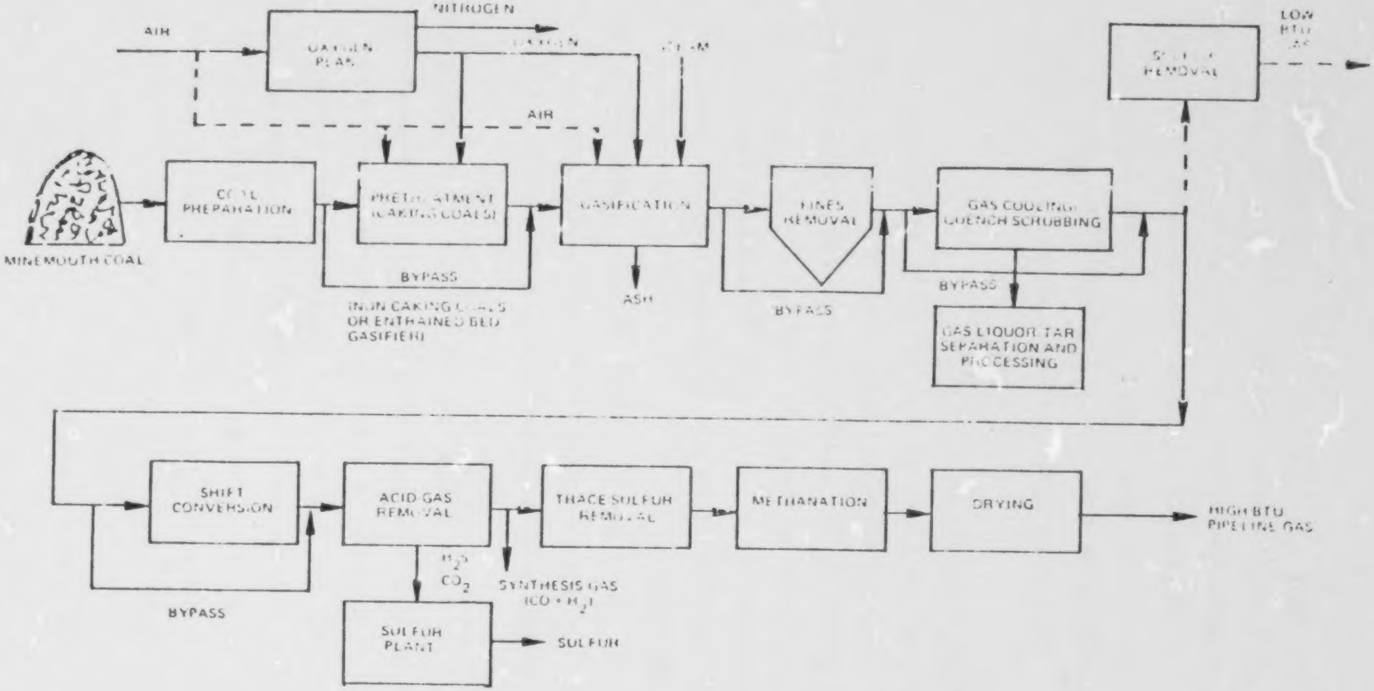
Coal arrives in the plant and is stored or used directly. Coal preparation may consist of any number of operations, including: crushing, grinding, drying, slurry preparation, briquetting, or partial oxidation.

In the gasifier, the coal is reacted with steam and oxygen (pure or as air for low Btu gas) at elevated temperatures and, atmospheric or elevated pressure. The products are related to the temperature and pressure of the reaction. The hot, raw product is normally scrubbed to cool it to the point where higher boiling components such as tar and phenols can be removed, and to remove particulates.

If methanation is desired, a shift reactor is normally used to provide a 3:1 ratio of H_2 to CO by the following reaction:

$$CO + H_2O = CO_2 + H_2$$

An acid gas removal unit to remove H_2S and CO_2, if desired, is the next step in the reaction sequence. A number of techniques


AIR
OXYGEN PLANT
NITROGEN
OXYGEN
STEAM
AIR
MINEMOUTH COAL
COAL PREPARATION
PRETREATMENT (CAKING COALS)
BYPASS
(NON CAKING COALS OR ENTRAINED BED GASIFIER)
GASIFICATION
ASH
FINES REMOVAL
BYPASS
GAS COOLING QUENCH SCRUBBING
BYPASS
GAS LIQUOR-TAR SEPARATION AND PROCESSING
SULFUR REMOVAL
LOW BTU GAS
SHIFT CONVERSION
BYPASS
ACID GAS REMOVAL
H2S
CO2
SULFUR PLANT
SULFUR
SYNTHESIS GAS (CO + H2)
TRACE SULFUR REMOVAL
METHANATION
DRYING
HIGH BTU PIPELINE GAS

(SOURCE: 95, p. 3-5)

FIGURE 2-1

SCHEMATIC FLOW DIAGRAM OF A COAL GASIFICATION PLANT are available for acid gas removal including absorption in a solvent, chemical conversion to another compound, and adsorption on solids. The reactions occurring are usually reversible so that the materials used are regenerated. This is the last step in low-Btu gas production.

The next step in the sequence for producing SNG or hydrogen is methanation by the following reactions:

$$CO + 3H_2 = CH_4 + H_2$$

$$CO_2 + 4H_2 = CH_4 + 2H_2O$$

SNG is then compressed to pipeline pressure and dried.

Auxiliary facilities may be required, including oxygen plants, sulfur recovery facilities, steam and power generation facilities, cooling towers, water and wastewater treatment facilities, and catalyst regenerators.

Eact of the steps in the overall gasification scheme are discussed in more detail in Appendix A. Effluent streams and potential constituents are also included.

2.2 COAL LIQUEFACTION

2.2.1 Introduction

Coal liquefaction is the conversion of the organic portion of coal into liquids and byproduct gases by the addition of hydrogen. There are several reasons for liquifying coal: liquid fuels are more versatile than solid fuels and are generally easier to store, transport and use; liquefaction facilitates removal of environmentally objectionable contaminants, e.g., sulfur, nitrogen, trace elements and ash; liquefaction provides a means of substituting an abundant indigenous resource for imported petroleum.

It is anticipated that the major use of coal liquids will be as fuels, including a clean boiler fuel for electric generating plants, and a synthetic fuel oil to produce gasoline, diesel fuel, and turbine fuels. Coal liquids may also be used as petrochemical feedstocks.

2.2.2 Technology Status

A wide range of process configurations and conditions exist within liquefaction technology. Currently some twenty-odd processes are in various stages of development by industry and federal agencies (16). The status of selected processes is presented in Table 2-2.

Four major categories of coal liquefaction processes may be identified:

- Direct hydrogenation - processes in which coal is catalytically hydrogenated under high pressure and temperature. Processes include H-Coal, Synthoil, and Berguis.
- Solvent extraction - technology in which a solvent is used as a hydrogen donor to promote liquefaction, again under high temperature and pressure. Candidate processes include Solvent Refined Coal (SRC I and SRC II), Exxon Donor Solvent (EDS), Co-Steam, and Solvent Extraction of Lignite.
- Pyrolysis - thermal decomposition of organic components in coal in the absence of oxygen to produce solids (char), liquids and gases. Processes include the Char-Oil-Energy-Development System (COED), Clean Coke System, Garrett System, Coalcon, and Toscoal.
- Indirect Liquefaction - gasification of coal with steam and oxygen to produce synthesis gas (carbon monoxide and hydrogen) which is catalytically converted to liquid products. Processes include the Fischer-Tropsch System and the Methanol System.

The four general processes are presented in Figure 2-2. The National Academy of Science has recently assessed coal liquefaction technology and concluded that of the four categories of coal liquefaction:

- The most promising solvent extraction process (Exxon Donor Solvent) and the most promising direct hydrogenation process (H-Coal) should be carried forward to the demonstration phase.

TABLE 2-2

COAL LIQUEFACTION PROCESSES

PROCESSES	DEVELOPMENT STATUS	DEVELOPMENT PLANS	POSSIBLE COMMERCIALIZATION*
Solvent Refined Coal	Pilot plant, 50 t/d	Demonstration plant operational FY 83	After 1985
H-Coal	PDU, 2.5 t/d	600 t/d Pilot plant operational FY 78	Near 1985
Exxon Donor Solvent	PDU, 1 t/d	250 t/d Pilot plant operational FY 80	After 1985
Synthoil	Bench Unit, 0.5 t/d	10 t/d PDU operational FY 79	After 1985
COED	Pilot plant, 36 t/d	None projected	After 1985
Co-Steam	CPU		
Clean Coke	PDU, 0.5 t/d		
Fischer-Tropsch	Fundamental research	None in this country	
ORC (Garrett)	PDU, 3 t/d	250 t/d Pilot plant	
Coalcon	Re-evaluation		Near 1985, unless cancelled
Methanol Synthsis			
TOSCOAL	Data unavailable		
Bergius	Bench unit, 0.5 t/d	PDU	

(SOURCE: 102, p. 10)

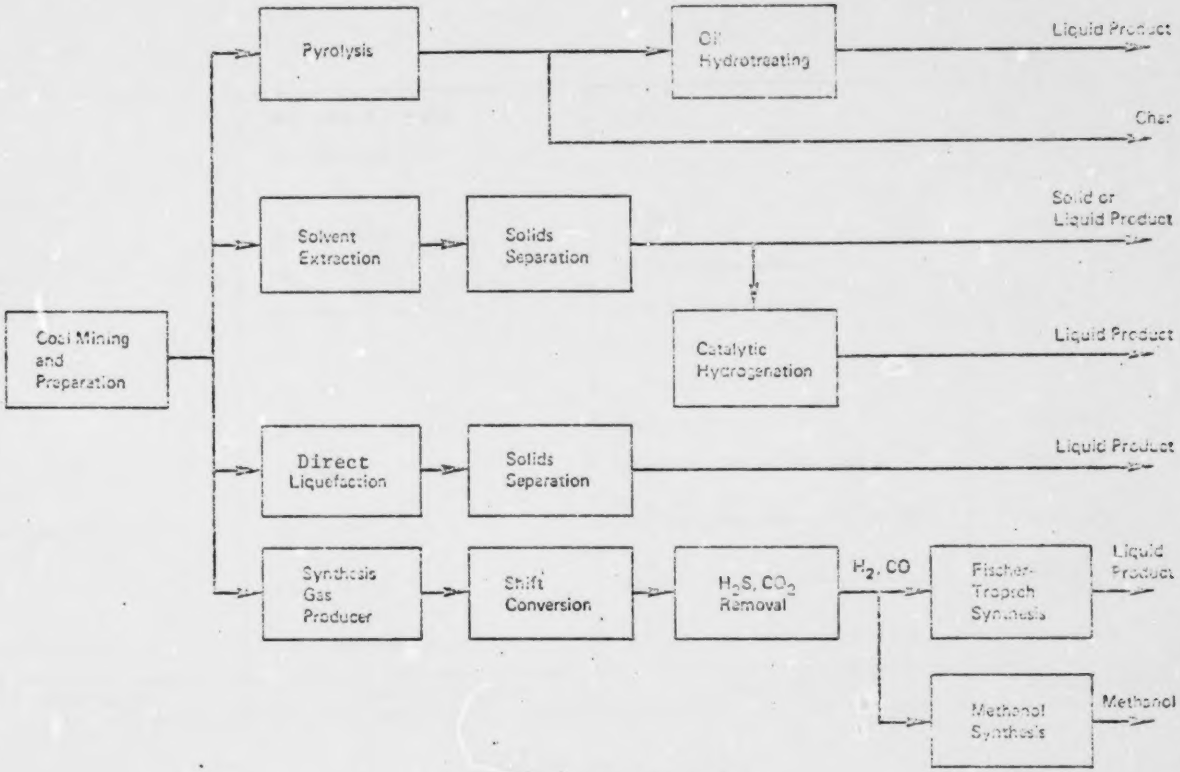

Coal Mining and Preparation
Pyrolysis
Oil Hydrotreating
Liquid Product
Char
Solvent Extraction
Solids Separation
Solid or Liquid Product
Catalytic Hydrogenation
Liquid Product
Direct Liquefaction
Solids Separation
Liquid Product
Synthesis Gas Producer
Shift Conversion
H2S, CO2 Removal
H2, CO
Fischer-Tropsch Synthesis
Liquid Product
Methanol Synthesis
Methanol

FIGURE 2-2
COAL LIQUEFACTION ROUTES

(SOURCE: 1, p. 18)

- Pyrolysis processes and indirect liquefaction processes do not appear promising for meeting the large liquid fuel requirements of the United States (1).

A recent environmental assessment of coal liquefaction technologies ranked liquefaction technologies based upon a number of criteria including state of development, availability, energy efficiency, probability of success, projected development costs and potential for emissions. The order of ranking for the candidate systems is as follows: (16).

- Solvent Refined Coal
- H-Coal
- Exxon Donor Solvent
- Synthoil
- COED
- COSTEAM
- Clean Coke
- Fischer-Tropsch
- ORC (Garrett)
- Coalcon
- Methanol Synthesis
- TOSCOAL
- Bergius

2.2.3 Process Chemistry

Bituminous, subbituminous and lignite coals may all be converted to liquids; anthracite tends to produce essentially all gas and is therefore more difficult to liquify. Most of the coal liquefaction technologies are now being developed with bituminous coals, however, several processes are being developed for using lignite (1).

Bituminous coal consists of clusters of aromatic carbon rings joined together in layers by various types of chemical bonds. The layers appear to be held together by physical interaction, e.g., hydrogen bonding or van der Waals forces.

When bituminous coal is heated to liquefaction temperatures it appears that the physical forces between the layers and the chemical bonds linking clusters together are ruptured, and producing free radicals which must be stabilized to ensure adequate production of liquid product.

In coal pyrolysis stabilization of the thermally produced free radicals may be accomplished by repolymerization or abstraction of hydrogen from the coal itself.

In solvent extraction processes the thermally produced free radicals can be stabilized by abstracting hydrogen from a donor solvent. Molecular hydrogen can act directly to stabilize free radicals if long enough reaction times, sufficiently high temperatures, or catalysts are employed (1).

2.2.4 Liquefaction Sequence

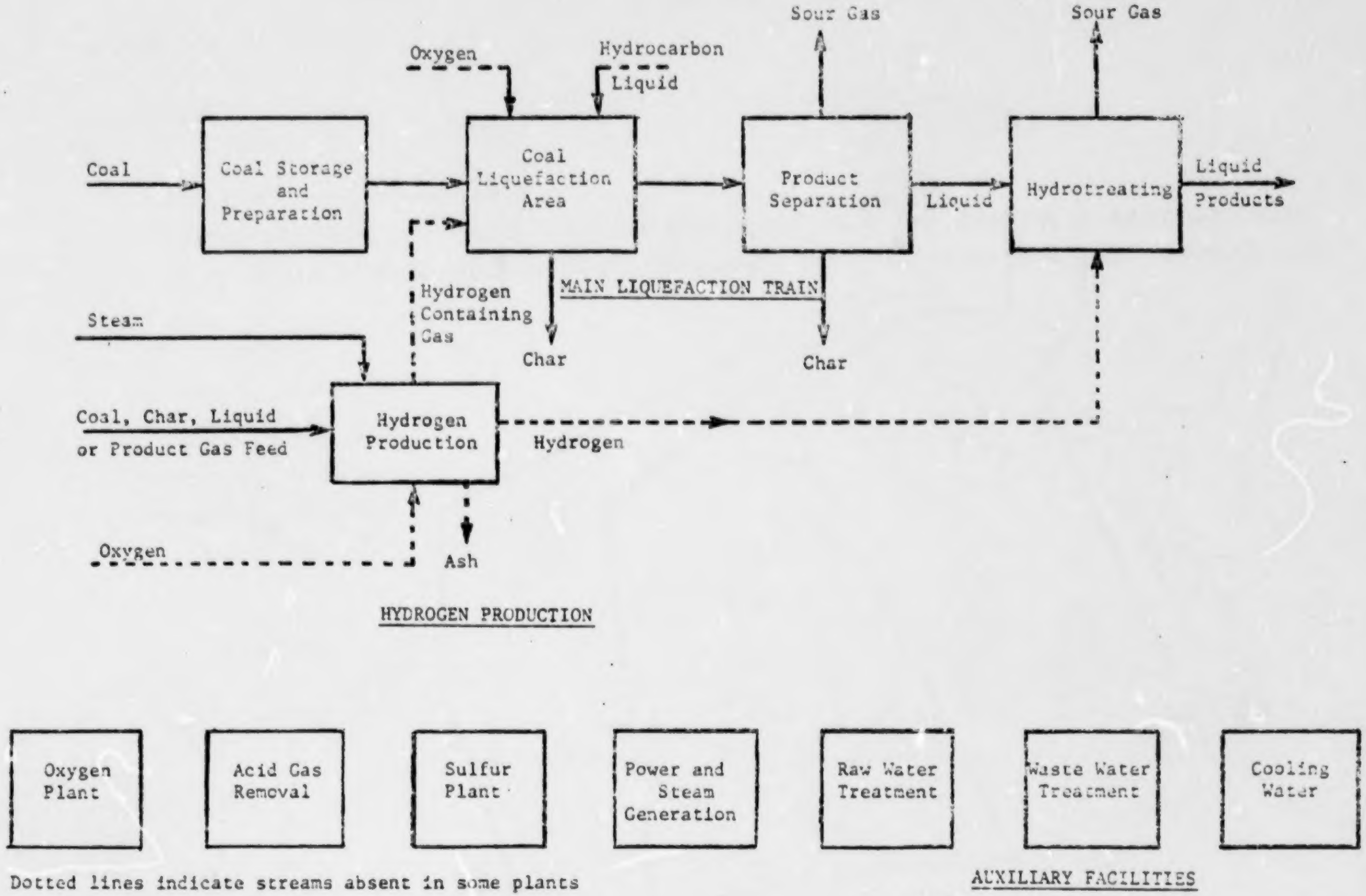
A generalized liquefaction scheme is shown in Figure 2-3. In the main liquefaction train there are four areas common to all essentially all processes. These are coal storage and preparation (grinding, drying, etc.), coal liquefaction, product separation, and hydrotreating. Hydrogen production is another major segment of the complex; the main train of this operation being similar to the gasification processes discussed in the previous section. Auxiliary facilities, which may be required, include: an oxygen plant, an acid gas plant, utilities, and pollution control systems (89).

2.3 IN SITU COAL GASIFICATION

2.3.1 Introduction

More than 85 percent of our nation's vast coal resource is not economically recoverable by conventional underground or strip mining. Underground coal conversion (UCG) processes could recover an estimated 1,795 billion tons of this unmineable coal by converting it in place to clean-burning gaseous and liquid fuels (39). Applicable reserves are presented in Figure 2-4.

The goal of in-situ gasification of coal is to convert coal, without mining, into combustible gases by initiating combustion of a

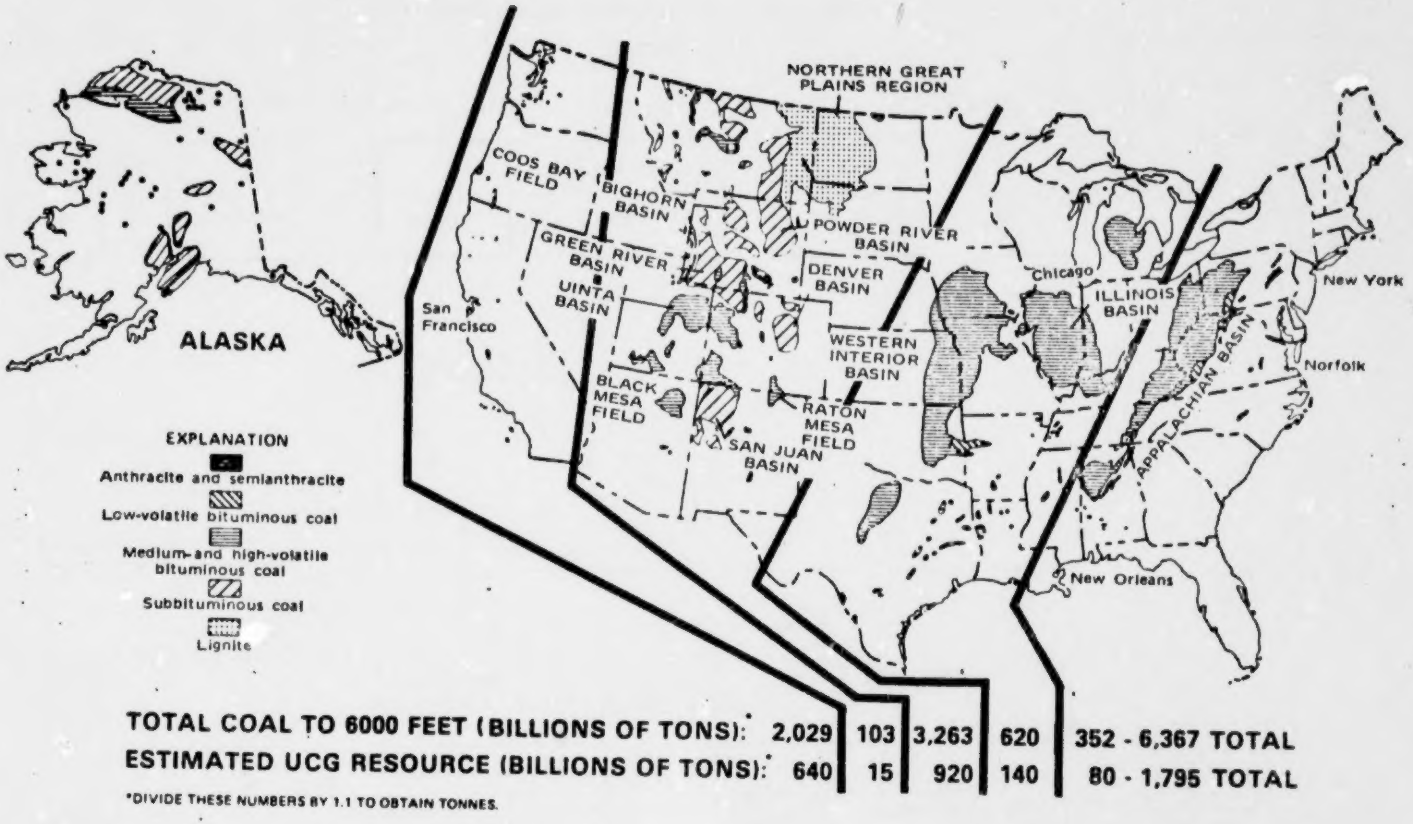

Coal
Coal Storage and Preparation
Oxygen
Hydrocarbon Liquid
Coal Liquefaction Area
Sour Gas
Product Separation
Liquid
Sour Gas
Hydrotreating
Liquid Products
MAIN LIQUEFACTION TRAIN
Char
Char
Hydrogen Containing Gas
Steam
Coal, Char, Liquid or Product Gas Feed
Hydrogen Production
Hydrogen
Oxygen
Ash
HYDROGEN PRODUCTION
Oxygen Plant
Acid Gas Removal
Sulfur Plant
Power and Steam Generation
Raw Water Treatment
Waste Water Treatment
Cooling Water
AUXILIARY FACILITIES

Dotted lines indicate streams absent in some plants

(SOURCE: 89, p. 56)

FIGURE 2-3

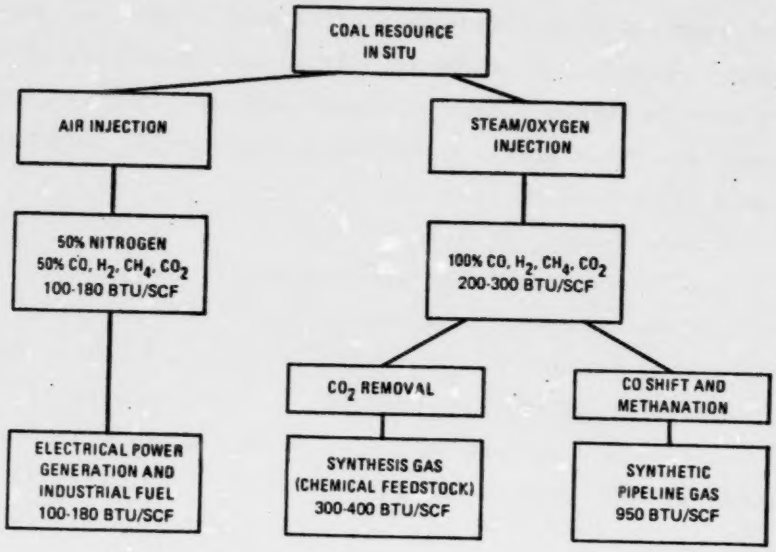
GENERALIZED COAL LIQUEFACTION SCHEME


ALASKA
EXPLANATION
Anthracite and semianthracite
Low-volatile bituminous coal
Medium-and high-volatile bituminous coal
Subbituminous coal
Lignite
NORTHERN GREAT PLAINS REGION
COOS BAY FIELD
BIGHORN BASIN
GREEN RIVER BASIN
UINTA BASIN
BLACK MESA FIELD
SAN JUAN BASIN
POWDER RIVER BASIN
DENVER BASIN
WESTERN INTERIOR BASIN
RATON MESA FIELD
ILLINOIS BASIN
APPALACHIAN BASIN
San Francisco
Chicago
New York
Norfolk
New Orleans
TOTAL COAL TO 6000 FEET (BILLIONS OF TONS):* 2,029 103 3,263 620 352 - 6,367 TOTAL
ESTIMATED UCG RESOURCE (BILLIONS OF TONS):* 640 15 920 140 80 - 1,795 TOTAL
*DIVIDE THESE NUMBERS BY 1.1 TO OBTAIN TONNES.

(SOURCE: 38, p. 159)

FIGURE 2-4

COAL FIELDS OF THE UNITED STATES


COAL RESOURCE IN SITU
AIR INJECTION
STEAM/OXYGEN INJECTION
50% NITROGEN
50% CO, H_2, CH_4, CO_2
100-180 BTU/SCF
100% CO, H_2, CH_4, CO_2
200-300 BTU/SCF
CO_2 REMOVAL
CO SHIFT AND METHANATION
ELECTRICAL POWER GENERATION AND INDUSTRIAL FUEL
100-180 BTU/SCF
SYNTHESIS GAS (CHEMICAL FEEDSTOCK)
300-400 BTU/SCF
SYNTHETIC PIPELINE GAS
950 BTU/SCF

(SOURCE: 39)

FIGURE 2-5
UNDERGROUND COAL GASIFICATION PRODUCTION
AND END USES

coal seam and injecting a current of air, oxygen, or oxygen and steam. In situ combustion results in the production of an artificial gas rich in carbon monoxide, carbon dioxide, hydrogen, hydrocarbon gases, and other gases, depending on the current injected and the method of combustion (15).

2.3.2 Technology Status

One future coal-based energy scenario estimates that UCG plants could comprise about 15 percent of the total coal usage by the year 2000 and 35 percent by 2050 (40). The primary reason for this optimistic appraisal of UCGs potential is that compared to conventional mining of coal combined with surface gasification, UCG offers a number of significant potential advantages: tripling recoverable coal reserves, minimizing health and safety problems associated in the conventional coal extraction, reducing surface disruption and solid waste disposal problems, reducing water consumption, and reducing socioeconomic impacts (39).

As shown in Figure 2-5, the demand for products of UCG logically falls into three areas, as a function of gasification and upgrading options:

- Low-Btu gas (produced by injecting air to the UCG reactor) for electric power generation and industrial fuels, at or very near the coal deposits.
- Medium-Btu gas (produced by injecting oxygen) for chemical feedstocks (e.g., ammonia and methanol production) for manufacturing facilities either onsite or short pipeline distances away.
- High-Btu gas (produced by injecting oxygen and then upgrading the raw product, in surface facilities) for injection into pipelines serving residential, commercial, and industrial customers.

Due to the favorable characteristics of the Western coals, it appears that UCG technology will first be commercialized in the West. As UCG technology develops for the more difficult Eastern coals, the large Eastern markets for power and gas can be penetrated (38).

Four major process options are being developed for underground gasification of coal:

- Linked Vertical Wells (LVW)
- Packed Bed (PB)
- Longwall Generator (LG)
- Steeply Dipping Beds (SDB)

Descriptions of the processes, including diagrams, are presented in Appendix A.

Of the four UCG options in the technology section, the production of low-Btu gas using linked vertical wells is closer to commercialization than any other. Successful completion of ongoing research may make low-Btu gas available for electric utility or industrial use by 1985.

Packed bed processes may provide commercial quantities of medium-Btu gas from western coal seam available by 1987.

The commercial application of longwall generators and steeply dipping beds technology is expected by the late 1980s, assuming the R&D scheduled for the early 1980s proves successful (38).

2.3.3 Process Chemistry

In most in-situ processes, two distinct phases are usually involved: carbonization and gasification. Air reacts exothermically with coal and/or char producing CO_2 and H_2O as combustion products. These hot gases react with char to form product gas consisting mainly of CO, H_2, and CH_4. The combustion heat also promotes carbonization (or devolatilization) of coal resulting in methane, char, H_2O and coal tar. Heavier components condense in the coal seam while the lighter components remain with the product gas (81).

The following reactions summarize some of the important steps involved in underground coal gasification:

Combustion	Coal + O_2 $H_2O + CO_2$
Hydrolysis	Coal + H_2O $CH_4 + CO$ + higher hydrocarbons
Carbonization	Coal $C + CH_4 + H_2$
Bouduard (undesirable side reaction)	$2CO$ $C + CO_2$
Water gas reaction (gasification)	$C + H_2O$ $H_2 + CO$
Shift reaction	$CO + H_2O$ $H_2 + CO_2$
Methanation	$3H_2 + CO$ $CH_4 + H_2O$

The extent to which each of these reactions predominates and/or can be controlled under in-situ conditions is one of the principal subjects of current technical investigations (75,81).

2.3.4 In-situ Gasification Sequence

In-situ gasification consists of pregasification, gasification, production, surface processing (if necessary) and support systems.

The main feature of pregasification is preparation of the bed to increase its permeability. Some coal seams are naturally quite permeable and do not require "pregasification," however the majority of coal seams do require some pretreatment.

Gasification involves introducing the gasifying agents (oxygen, steam and/or carbon dioxide) contacting these agents with the coal, and recovering the reaction products.

Surface processing may include: mechanical separation to separate heavy entrained hydrocarbons; amine absorption to remove hydrogen sulfide; sulfur removal; and methanation to produce high-Btu gas.

Surface support facility requirements may include oxygen and steam plants, and possibly water treatment units.

3.0 SOURCE CHARACTERIZATION

3.1 INTRODUCTION

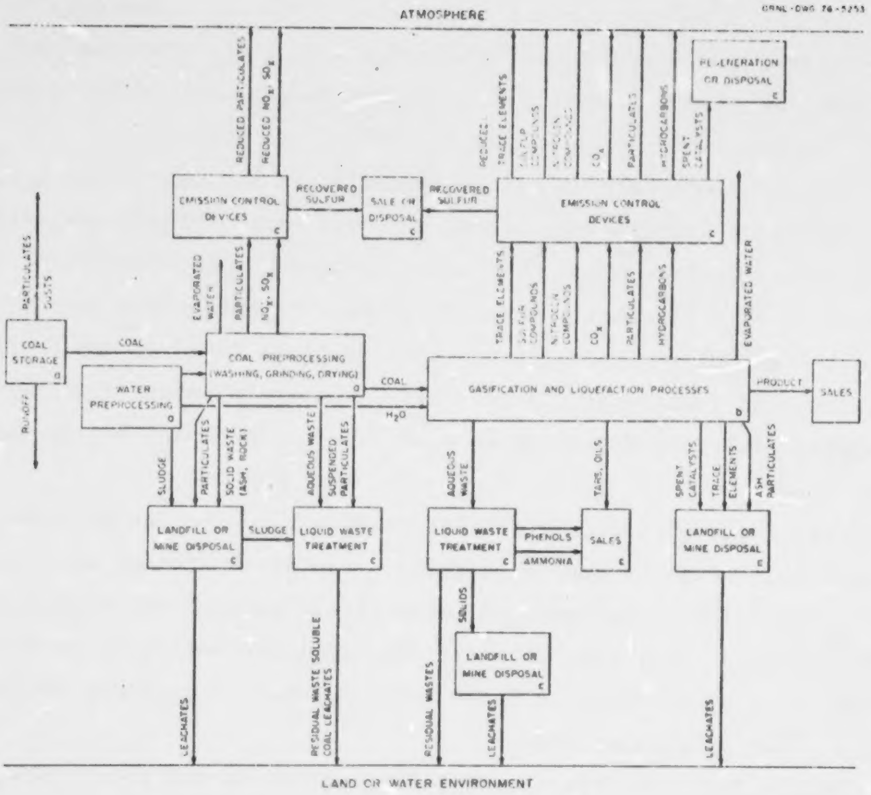
The environmental impacts associated with coal conversion operations range from conventional pollution and safety problems such as coal dust emissions to such ill-defined problems as fugitive gaseous emissions which may require special control systems.

Although liquefaction and gasification technologies have different processing units, similarities of their waste streams and waste management practices allow them to be discussed concurrently for the purpose of this document. However, it must be emphasized that stream characterization is not complete; and available data may not be representatives of commercial plants. Also, the exact nature and quantity of wastes will vary according to coal type, operational design and plant size.

Discharges with potential environmental impacts can be produced at each main stage of coal conversion: feedstock storage and preparation, conversion operations and waste stream control and treatment, as shown in Figure 3-1. The potential for fugitive emissions is presented, by process step, in Table 3-1. Appendix A presents pollutant streams by process step.

Wastes from coal storage, handling, crushing and classification processes can be handled using available techniques for controlling dust emissions, disposal of mineral wastes and handling runoff water from storage piles. The control of air emissions, e.g., volatile hydrocarbons and trace elements, from coal dryers, briquetting, and partial oxidation may present more difficult problems. The exact character of these discharges, the limits to which they must be controlled and the adequacy of available control technology have not yet been determined (15).

Wastes from coal conversion units are being identified. Numerous steps in coal conversion may produce emissions that are potential


ATMOSPHERE
ORNL-DWG 76-5253
REDUCED PARTICULATES
REDUCED NO$_x$, SO$_x$
EMISSION CONTROL DEVICES
c
RECOVERED SULFUR
SALE OR DISPOSAL
c
RECOVERED SULFUR
REDUCED TRACE ELEMENTS
SULFUR COMPOUNDS
NITROGEN COMPOUNDS
CO$_x$
PARTICULATES
HYDROCARBONS
SPENT CATALYSTS
REGENERATION OR DISPOSAL
c
EMISSION CONTROL DEVICES
c
PARTICULATES
DUSTS
EVAPORATED WATER
PARTICULATES
NO$_x$, SO$_x$
TRACE ELEMENTS
SULFUR COMPOUNDS
NITROGEN COMPOUNDS
CO$_x$
PARTICULATES
HYDROCARBONS
EVAPORATED WATER
COAL STORAGE
a
COAL
COAL PREPROCESSING (WASHING, GRINDING, DRYING)
a
COAL
GASIFICATION AND LIQUEFACTION PROCESSES
b
PRODUCT
SALES
WATER PREPROCESSING
a
H$_2$O
RUNOFF
SLUDGE
PARTICULATES
SOLID WASTE (ASH, ROCK)
AQUEOUS WASTE
SUSPENDED PARTICULATES
AQUEOUS WASTE
TARS, OILS
SPENT CATALYSTS
TRACE ELEMENTS
ASH PARTICULATES
LANDFILL OR MINE DISPOSAL
c
SLUDGE
LIQUID WASTE TREATMENT
c
LIQUID WASTE TREATMENT
c
PHENOLS
AMMONIA
SALES
c
LANDFILL OR MINE DISPOSAL
c
SOLIDS
LANDFILL OR MINE DISPOSAL
c
LEACHATES
RESIDUAL WASTE SOLUBLE COAL LEACHATES
RESIDUAL WASTES
LEACHATES
LEACHATES
LAND OR WATER ENVIRONMENT

(SOURCE: 15, p. 4-8)

FIGURE 3-1

EMISSION FATES FOR COAL CONVERSION PROCESS

TABLE 3-1

POTENTIAL FOR FUGITIVE EMISSIONS FROM ADVANCED COAL PROCESS MODULE

Process	Process Step	Pressure	Temperature	Potentially Hazardous Volatiles	Corrosiveness	General Housekeeping	Potential for Hazardous Fugitive Emissions
Liquefaction							
	Slurry Preparation	low	low	med	low	med	med
	Reactor	high	high	high	med	med	high
	Reactor Separator	med-high	high	high	med	med	high
	Condenser	low	med	med	high	med	high
	Filtration	low	med	high	med	med	high
	Water-Oil Separation	med	low	high	low	poor	med
	Fractionation	low	med	high	med	med	high
	Hydrotreating	high	high	high	med	med	high
	Hydrocracking	high	high	high	med	med	high
	Storage	low	low	med	low	med	high
	Acid Gas Treatment	low	low	high	med	med	med
	Hydrogen Separation	high	high	low	med	med	med-high
	Sulfur Plant	low	high	high	med	med	low
Gasification							med-high
	Coal Preparation	low	low	med	low	poor	med
	Oxygen Blown Gasification	high	high	high	med-high	med	med-high
	Quenching and Cooling	low	med-high	high	high	med	med-high
	Tar Separation	low	low	high	med	poor	high
	Shift Conversion	high	high	low	low	good	low-med
	Phenol Recovery (Phenosolvan Process)	low	med	high	med	med	med
	Acid Gas Removal (Rectisol Wash)	low	low	high	low	med	med
	Methanation	high	high	low	low	good	low
	Further Gas Purification (Rectisol Wash)	low	low	med	low	med	med
	Sulfur Recovery (Stretford Process)	low	low	med	low	med	low-med
	Air Blown Gasification	high	high	high	med-high	med	med-high
	Storage	low	low	med	low	med	med

(SOURCE: Adapted from 19)

pollutants. Among the potential sources of pollutions are gasification, tar separation, shift conversion, quenching, gas purification, methanation, compression, and dehydration, hydrogenation, pyrolysis, hydrotreating, and solids separation. Effluents of particular importance in conversion units appear to be acid gas, pyrolysis gas, ammonia stripping gas, ash, tars, chars, filter cakes, particulates, spent catalysts, process wastewater, cooling water, and blowdown water.

Product and byproduct streams containing coal-derived compounds and added materials are capable of producing emissions through incomplete recovery, evaporation of constituents, spills, or leaks.

Control and treatment processes, applied to minimize pollutants produced in the conversion areas, include particulate control, stack gas control, acid gas treatment, wastewater treatment, char treatment, tar treatment, heat control, and noise control. Cleanup processes can generate their own pollutants requiring treatment.

Emissions from pollution treatment facilities include converted and fugitive pollutants derived from process emission streams and constituents used within the treatment system. Emission disposal options include the resale of by-products to other industries, use as landfill or minefill, or return for further treatment.

Pollutants which may be contained in emission streams include sulfur (S_2, S_4, H_2S, COS, CS_2, mercaptans, thiophenes), nitrogen (NO_x, HN_3, HCN, thiocyanates), particulate matter (debris, fines, ash, chars), trace elements, wastewaters, organics, spent catalysts, thermal effluents, noise, carbon dioxide, and radioactivity (15).

3.2 PRECAUTIONARY CONSIDERATIONS

Information on the identity, distribution, quantity and concentration of potential pollutants throughout the entire fuel cycle and for all media is essential for the future development of guidelines, criteria and regulatory requirements at the federal, state and local levels.

Pollutant source characterization may be accomplished from several different perspectives:

- Controlled vs. uncontrolled emissions -it would be advantageous to establish the levels of pollutants that would be expected after use of the best treatment technologies. Unfortunately current information does not permit such an effort. Preliminary estimates of the treatability of some streams may be made, but verification will be contingent upon adequate stream characterization and application of proposed controls to truly representative streams.

- Routine vs. transient emissions - Pollutants which are routinely emitted are of concern on a day-to-day basis. Transient pollutants which may result from process upsets, shutdown or startup may be more difficult to monitor or predict, but must be considered due to their potential for environmental, health, and safety impacts.

- Development vs. commercial plant emissions - The degree to which pollutant characterization represents a coal conversion industry is partially a function of the stage of development of the source plant. Data obtained at less than demo plant scale may or may not be representative and/or scalable for commercial operations. Unwary extrapolation of data may produce incorrect results. The relative advantages and disadvantages of process variable/effluent experiments at various scales are presented in Table 3-2. Pilot-plant and full-scale-plant streams are compared for the CO_2 Acceptor process in Table 3-3. Examples of the type of research appropriate for various development stages are presented in Table 3-4.

- Comparability of results -In comparing stream composition and quantity from various plants, consideration should be given to differences in test conditions, e.g., coal feed, process operating conditions, application of pollutant control processes, stage of technology development, and characterization equipment and techniques.

3.3 STATE OF KNOWLEDGE

State-of-the-art reviews on characterization of substances in energy-related effluents have been conducted by several investigators.

TABLE 3-2

RELATIVE ADVANTAGES AND DISADVANTAGES OF PROCESS VARIABLE/ EFFLUENT EXPERIMENTS AT VARIOUS SCALES

Relative Advantages	Relative Disadvantages
Pilot Plant Scale	
• Large, measureable flows of individual effluent constituents	• Complications in effluent measurement due to lag time, damping, variability
• Extended operating periods (days)	• Process variable interactions and effects difficult to resolve
• Well-defined operating conditions	• Process conditions cumbersome to change
Process Development Unit (PDU) Scale	
• Flexibility regarding change of process conditions	• Potential sampling problems due to reduced effluent production rates
• Test objectives can be set independent of process engineering schedules	• Individual process variable effects still not decoupled
• Scale sufficient to preserve material balance capabilities	• Interpretation and scale-up of results provide problems, particularly for studies with caking coals requiring pretreatment
Bench Scale	
• Low cost method for testing specific relationships between process variables and effluents	• Must operate at simulated gasifier conditions on model compounds
• Process variable effects can be decoupled	• Scale can provide difficulties in making accurate material balances
	• Scale-up of results uncertain at best

(SOURCE: 91, p. 29)

TABLE 3-3

COMPARISON OF CO_2 ACCEPTOR PILOT-PLANT AND FULL-SCALE-PLANT WASTE STREAMS

Pilot plant	Full-scale plant
Fugitive dust from lignite and dolomite storage and receiving areas	Fugitive dust from lignite and dolomite storage and receiving areas
Fugitive dust from dolomite grinding mill	Fugitive dust from dolomite grinding mill
Lignite drying and grinding mill vent gas	Lignite drying and grinding mill vent gas to SO_2 scrubber
Lignite preheater scrubber vent gas	Lignite preheater vent gas to furnace
Regenerator flue gas vent	Regenerator flue gas to lignite drying
Flare	Flare
No sulfur plant	Sulfur-plant tail gas
No ammonia recovery	Fugitive emissions from NH_3 purification and storage
Drains from receiving and storage areas	Drains from receiving and storage areas
Process drains (waste sump)	Process drains
Cooling tower blowdown (waste sump)	Cooling tower blowdown
Gasifier quench tower blowdown	Gasifier quench tower blowdown to sour water stripper
SO_2 scrubber blowdown	Acid gas scrubber blowdown
Flare condensate	Flare condensate
Regenerator quench tower blowdown	Dry methods of power and heat recovery
Lignite grinding fines slurry	Lignite grinding fines to lignite furnaces
Lignite preheater fines slurry	Preheater off-gas and dust to lignite furnace
No sulfur plant	Sulfur plant tail gas scrubbing blowdown
Boiler blowdown (waste sump)	Boiler feedwater system blowdown
No limestone scrubber	Limestone scrubber blowdown
Regenerator cyclone ash	Chance reaction slurry[a]
Dolomite fines	Dolomite fines (used to make limestone slurry)
Purged acceptor	Chance reaction slurry[a]
Gasifier cyclone ash and char	Gasifier cyclone ash and char to regenerator
Flue gases from natural-gas-fired boilers and furnaces	Ashes and flue gases from lignite-fired furnaces and boiler (furnace flue gases are scrubbed with limestone slurry)
Solids from waste pond	Solids from evaporation pond

[a] Purged acceptor and regenerator cyclone ash should contain a large amount of calcium sulfide (CaS). In a full-scale plant, this will be slurried with water and subjected to a CO_2 gas stream to produce $CaCO_3$ and H_2S via the chance reaction:

$$CaS + H_2O + CO_2 = CaCO_3 + H_2S.$$

The H_2S will be routed to sulfur recovery, whereas the $CaCO_3$ may be returned to the process or sent to the landfill.

(SOURCE: 106, p. 4a.6.2.3)

TABLE 3-4

SAMPLING EFFORTS

State of Development	PROCESS CHARACTERIZATION WASTE STREAM ANALYSIS			ESTIMATED SPHERE OF INFLUENCE			
	Identify Major Species	Identify Trace Constituents	Determine Emission Rates	Describe Existing Environment	Identify Pathways for Pollutant Transport	Use Models to Predict Ambient Concentrations	Media Tests
Conceptual Stage	Δ	Δ	Δ	Δ	Δ	Δ	Δ
Laboratory Bench Apparatus	0	Δ	Δ	Δ	Δ	Δ	Δ
Pilot Plant	0	0	0	0Δ	0	0	Δ
Demonstration Plant	0	0	0	0	0	0	0
Full-Scale Commercial Plant	0	0	0	0	0	0	0

NOTE: 0 = indicates sampling need
Δ = indicates no sampling requirement

(SOURCE: 41)

The reviews indicate that data availability varies among coal conversion categories and indivdual processes.

A state-of-the-art review was conducted by Research Triangle Institute to identify gaps in existing and probable future data on chemical elements and volatile organic compounds in solid waste and aqueous effluents from coal mines, coal-fired power plants, coal liquefaction and gasification plants, and non-coal fossil fuels. The reviewers found that with regard to coal conversion processes, a paucity of data existed on the organic composition of liquid and solid effluents from in situ coal and lignite gasification, and low-Btu gasification of coal and lignite. Meager data were available for the organic composition of liquids and solids from coal processing. In general it was concluded that,

> "the research conducted to date on the analysis for organics in liquid and solid effluents was highly inadequate for the purpose of understanding the efficiency of the energy-related processes and the potential environmental impact. Much of the data were based on 'paper' studies that merely conjectured as to the probable pollutants that would be associated with the energy-related activity. When evaluating the available data on the elemental and organic composition of effluents from energy-related processes according to the chosen criteria--particularly the thoroughness of the study and its ability to provide specific individual chemical information for all the species present in the effluents--we found few significant energy-related studies." (99)

Radian's survey of available data on the environmental aspects of low/medium-Btu gasification processes concluded that although a significant amount of data is available on environmental problems associated with coal gasifier operations, the data are inadequate for making comprehensive environmental and control technology assessments. Major deficiencies were found in the areas of characterizing the emissions of minor and trace contaminants from gasification processes (particularly trace organics). The survey also indicated a general lack of information on fugitive emissions and minor process vent streams (30).

A recent environmental assessment of coal liquefaction has concluded that,

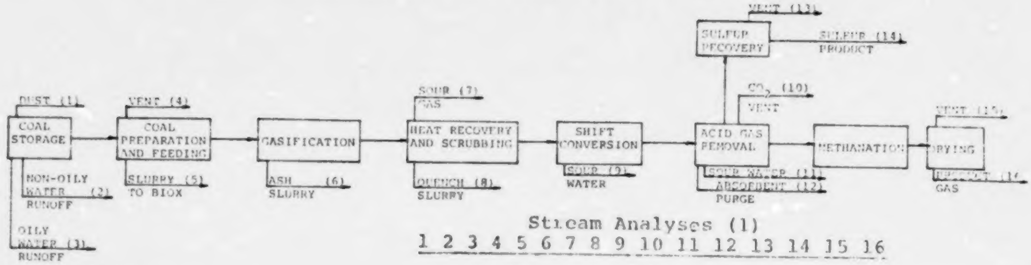
> "Existing data for the environmental discharges on the different systems are fragmentary and usually may be characterized as:
>
> - Product and waste descriptions based on hydrocarbon chain length, boiling point ranges, viscosities, and element contents (sulfur, nitrogen, carbon-hydrogen ratios, metals, etc.)
> - Qualitative analysis for specific organic compounds, often for known carcinogenic effects.
> - Out-of-date and/or partial quantitative analysis of products."

The assessment indicated that most of the existing data for environmental effects are for the product, or the solid and residue wastes, and that, "although voluminous data exist on the presence of biologically active organic compounds in liquefaction products and toxic pollutants have been identified in solid wastes and wastewaters, their environmental effects have not been documented." (16)

An assessment of characterization data for coal conversion wastes is being conducted by Pullman Kellogg to provide a basis for control technology development. Availability of information on emissions from coal gasification and coal liquefaction are presented in Tables 3-5 and 3-6, respectively (14).

Waste streams and potential constituents are presented for each process step in Appendix A.

TABLE 3-5
AVAILABLE INFORMATION ON EMISSIONS FROM COAL GASIFICATION PROCESSES

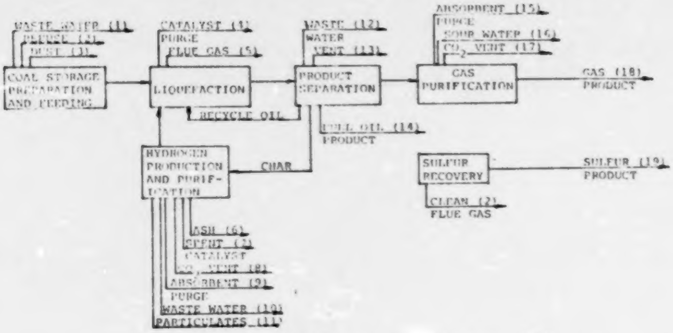

COAL STORAGE
DUST (1)
NON-OILY WATER (2) RUNOFF
OILY WATER (3) RUNOFF
COAL PREPARATION AND FEEDING
VENT (4)
SLURRY (5) TO BIOX
GASIFICATION
ASH (6) SLURRY
HEAT RECOVERY AND SCRUBBING
SOUR (7) GAS
QUENCH (8) SLURRY
SHIFT CONVERSION
SOUR (9) WATER
ACID GAS REMOVAL
CO2 (10) VENT
SOUR WATER (11)
ABSORBENT (12) PURGE
SULFUR RECOVERY
VENT (13)
SULFUR (14) PRODUCT
METHANATION
DRYING
VENT (15)
PRODUCT GAS

	Stream Analyses (1)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
CO_2 Acceptor					P	A	A	A			A				A	A
Synthane				A	P	A		A	A						A	
HyGas (Steam/Ox.)						P		A	A	Q			Q		A	A
HyGas (Steam/Iron)				A	A	P		P	A		A		Q		A	A
Lurgi (Dry Ash)					P	P	A	A		Q			Q		Q	A
Lurgi (Slag Ash) (2)																
Bi-Gas						P		P	P				P	P	P	P
Battelle Agglomerating Ash (3)																
COGAS (4)																
Hydrane						A										A
Koppers-Totzek						A		A								A
Winkler				A		P										A
Westinghouse (15)																
Foster Wheeler (6)																
AI Molten Salt (7)																A
Combustion Engineering (8)						Q										Q
Riley-Morgan						P			P							A
Wellman-Galusha									P							A
U-Gas				Q		A			Q				Q			A
Babcock & Wilcox (9)				A				A				A	A			
ERDA/MERC (10)																
Texaco (2)																
BCR (11)																
Woodall-Duckham (12)																

(1) A = Analysis, either real or conceptual; P = Partial analysis; Q = Quantities only.
(2) Proprietary. No data released to date. Possible future release.
(3) PDU operation expected late 1977. Effluent data available possibly in early 1978.
(4) Development mostly proprietary, very little effluent data. Now being evaluated by ERDA vs. Slagging Lurgi.
(5) Emphasizes turbine development. Little effluent data available.
(6) Conceptual design only. No data. Used Bi-Gas gasifier.
(7) PDU scheduled for 1978-9 operation. Very limited data mostly on proces
(8) Pilot plant effluent data expected in six-twelve months.
(9) Will not be built. Bi-Gas is very similar and was built by B&W.
(10) Process development with no published effluent data.
(11) Pilot Plant. No effluent data.
(12) Commercial operation. No published effluent data.

(SOURCE: 14, p. 426)

TABLE 3-6
AVAILABLE INFORMATION ON EMISSIONS FROM COAL LIQUEFACTION PROCESSES


WASTE WATER (1)
REFUSE (2)
DUST (3)
COAL STORAGE PREPARATION AND FEEDING
CATALYST (4)
PURGE
FLUE GAS (5)
LIQUEFACTION
RECYCLE OIL
WASTE (12)
WATER
VENT (13)
PRODUCT SEPARATION
FUEL OIL (14)
PRODUCT
ABSORBENT (15)
PURGE
SOUR WATER (16)
CO_2 VENT (17)
GAS PURIFICATION
GAS (18)
PRODUCT
HYDROGEN PRODUCTION AND PURIFICATION
CHAR
ASH (6)
SPENT (7)
CATALYST
CO_2 VENT (8)
ABSORBENT (9)
PURGE
WASTE WATER (10)
PARTICULATES (11)
SULFUR RECOVERY
SULFUR (19)
PRODUCT
CLEAN (20)
FLUE GAS

Stream Analyses (1)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
COED (2)	P	Q				P		Q		A		A		Q		A			Q	A
Clean Coke (3)																		Q		
SRC (4)			Q			Q								P			A	P	Q	A
H-Coal (5)				Q								Q		P				Q	Q	
Synthoil (6)						A						Q		A				Q	Q	
Donor Solvent (7)																				

(1) A = Analysis, either real or conceptual; P = Partial analysis; Q = Quantities only.

(2) Information from conceptual design for COED combined with COGAS.

(3) No published effluent information to date. Data expected by end of 1977.

(4) Information from conceptual design of SRC II process.

(5) Pilot plant construction to be completed in 1978, operation scheduled into 1980.

(6) PDU operation to start in 1978.

(7) No published effluent information to date. Environmental Assessment scheduled for late 1977 completion.

(SOURCE: 14, p. 427)

4.0 POTENTIAL POLLUTANTS

4.1 INTRODUCTION

The purpose of coal conversion is to convert an environmentally unacceptable fuel into a clean, convenient gas or liquid which when used as a fuel will not degrade environmental quality. Consideration must be given to the potentially large environmental effects of conversion facilities to preclude merely transferring environmental impacts of conventional coal utilization facilities to coal conversion facilities.

Total potential daily emissions for a gasification plant producing 250 million scfd of pipeline gas from Illinois No. 6 coal (3.7% sulfur) have been estimated to range from: 300-450 tons of sulfur, primarily as H_2S; 0 to 2 tons of hydrogen cyanide; 10-70 tons of phenols; 0 to 400 tons of oils and tars; and up to 5 pounds of mercury. Up to 5000 tons of solid wastes and/or char may also be produced daily (55).

As in coal gasification, one of the concerns of coal liquefaction is that, in the attempt to convert coal to a clean liquid fuel, sizeable environmental impacts are not transferred from conventional coal utilization facilities to liquefaction plants. Coal liquefaction facilities will process less coal than gasification plants but will still have the potential for a sizeable impact.

Although knowledge of the wastes and emissions from coal conversion processes is still incomplete, it is known that wastes will be generated during each main process stage. Many of these wastes are largely controllable or convertible to environmentally acceptable forms, however, more serious problems may arise from possible fugitive emissions produced by inadequate containment of process streams or incomplete treatment of wastes.

The coal conversion processes discussed in this report are largely untried under conditions approximating commercial application.

Consequently, although a number of potential pollutants have been identified, it is impossible at this point to predict in what combinations and in what form they will come into contact with the environment. The design of the individual plant, its pollution control strategies and its environmental setting will influence the extent and occurrence of pollution pathways (78).

In considering pollution control needs, it is also necessary to consider the inter-relationships existing among liquid, gaseous and solid wastes. For example, spent catalysts can present a solids disposal problem if not reused, or cause an air pollution problem when regenerated.

Knowledge of the environmental interactions of possible coal conversion pollutants - hydrocarbons, trace elements, sulfur oxides, and nitrogen oxides - are necessary to assess the environmental stress presented by a coal conversion facility.

In the following sections potential pollutants are described by major category: air, water, solids, organics, trace elements, products and by products, and transient pollutants.

Screams in which the pollutants are found are presented in Appendix A.

4.2 AIR

Because coal gasification and liquefaction occurs in a closed system, it should be easier to control the emission of pollutants to the atmosphere. However, processing steps, auxiliary equipment, and fugitive emissions present possibilities for air emissions, and it is important to know the possible gaseous compounds. In situ gasification may present air emission problems as they are not contained in a closed system.

Generally, gaseous emissions from coal conversion plants originate from the following sources: raw material handling and pretreatment; vent gases from start-up, shutdown and lock hopper operations;

by-product recovery, storage and upgrading; waste treatment; acid gas removal and sulfur recovery; catalyst regeneration; and power generation (74).

Fugitive emissions escape from sources such as valve stems, flanges, loading racks, equipment leaks, pump seals, sumps, etc. Because conversion facilities are closed systems the fugitive losses may be the major source of emissions. Many processes also operate under pressure which increases the potential for fugitive emissions. The assessment of fugitive emissions is difficult because there is no operating experience with gasification plants on the commercial scale envisioned for future use.

Potential pollutants that may arise in one or more effluent streams are sulfur oxides, nitrogen oxides, particulates, reduced sulfur compounds, ammonia, hydrogen cyanide, phenols, carbon oxides, tars, oils, trace elements (73). See Table 4-1.

Sulfur dioxide emissions can come from the sulfur recovery plant tail gas and the stack gases of auxiliary combustion systems. Emissions of nitrogen oxides are a result of fuel combustion in boilers and process heaters. Particulate matter can enter the atmosphere as fugitive dust from coal handling operations or as stack gas emissions from combustion or process unit operation. Carbon dioxide is also emitted to the air from the processing operations.

Because organic sulfur is difficult to remove during coal pretreatment and because about 90 percent of the organic sulfur is converted to hydrogen sulfide in both gasification and liquefaction, this form of sulfur is estimated to be the major sulfur contaminant in gas streams. Other sulfur species which may be present, include: hydrogen sulfide, carbonyl sulfide, carbon disulfide, mercaptans, and thiophenes. Hydrogen sulfide and sulfur dioxide are readily removed from gas streams, but carbonyl sulfide and carbon disulfide can pass through sulfur traps and be emitted to the atmosphere (15).

TABLE 4-1

COMPONENTS IN GASIFIER GAS, PPM

	Illinois No. 6 Coal	Illinois Char	Wyoming Subbituminous Coal	Western Kentucky Coal	North Dakota Lignite	Pittsburgh Seam Coal
H_2S....................	9,800	186	2,480	2,530	1,750	860
Carbonyl sulfide (COS)	150	2	32	119	65	11
Thiophene............	31	.4	10	5	13	42
Methyl thiophene.....	10	.4	-	-	-	7
Dimethyl thiophene...	10	.5	-	-	11	6
Benzene..............	340	10	434	100	1,727	1,050
Toluene..............	94	3	59	22	167	185
C_8 aromatics.........	24	2	27	4	73	27
SO_2..................	10	1	6	2	10	10
Carbon disulfide(CS_2)	10	-	-	-	-	-
Methyl mercaptan.....	60	.1	.4	33	10	8

(SOURCE: 59)

Most of the sulfur in coal is expected to be recovered from conversion streams as elemental sulfur, although the sulfur that reaches the stack gas as sulfur oxides and is collected by limestone scrubbing will end up as sulfate. Sulfur disposal may be a problem due to the large quantities produced: a plant processing 25,000 tons of 4% sulfur coal per day will produce 1000 tons of sulfur daily. See Table 4-2.

Nitrogen is introduced into the conversion process not only from the nitrogen content of the coal but also from the air used as an oxygen source. For example, a Synthane process using 3650 tons of oxygen per day separates and vents 330 million scf, or 12,200 tons, of nitrogen daily. thus, nitrogen emissions are primarily elemental nitrogen, although nitrogen oxide levels, which can be environmentally significant, depend upon process designs and the nitrogen content of coal (15). See Table 4-3.

The formation of oxides of nitrogen in flares, furnaces, and oxidizers is probable in the combustion area. If an amine process is used in acid gas removal, ambient concentrations of amines may be present. The two species may react to form nitrosamines (51).

In addition to sulfur dioxide, nitrogen oxides, particulates and carbon dioxide, coal conversion processes are likely to emit significant amounts of ammonia, principally from storage and loading of by-product ammonia. Small quantities of hydrogen sulfide (H_2S) and hydrogen cyanide (HCN) may be encountered within the plant and near the ground due to fugitive losses.

Fugitive H_2S and HCN emissions may constitute an in-plant problem but are unlikely to affect the surrounding environment. Ammonia will be produced at a significantly higher rate and it is possible that under certain circumstances vapor could escape beyond the plant boundaries.

Hydrocarbon emissions occur by evaporation of hydrocarbons dissolved in liquid waste or in cooling streams, fugitive emissions, and incomplete combustion at auxiliary plant facilities. Carbon monoxide,

TABLE 4-2

ESTIMATES OF SULFUR RECOVERY AND DISCHARGES FOR THE BI-GAS AND SRC PROCESSES (TONS PER DAY)

Description	Appalachian region	Eastern interior region	Fort Union region	Powder River region	Four Corners region
		Bi-Gas			
Input sulfur					
To refinery	879	1985	578	408	458
To boilers	167	378	110	77	87
Total	1046	2363	688	485	545
Sulfur discharge[a]					
H_2S in wastewater	4	9	3	2	2
SO_2 from boilers to atmosphere	67	151	44	32	35
95% tail gas recycle					
Recovered elemental sulfur	997	2255	656	464	523
Total SO_2 to atmosphere	58	152	44	32	35
Total Na_2SO_4 produced	140	315	92	66	73
No tail gas recycle					
Recovered elemental sulfur	991	2244	652	461	520
Total SO_2 to atmosphere	78	176	51	37	41
Total Na_2SO_4 produced	139	315	92	65	73
		SRC			
Sulfur input, total	1046	2363	687	485	546
Sulfur discharges					
Sulfur in products	267	254	250	267	252
H_2S in wastewater	2	6	Trace	Trace	1
95% tail gas recycle					
Recovered elemental sulfur	770	2030	430	210	288
SO_2 to atmosphere	2	2	2	2	2
Na_2SO_4 produced	43	114	24	12	16
No tail gas recycle					
Recovered elemental sulfur	766	2020	429	210	286
SO_2 to atmosphere	10	22	6	2	4
Na_2SO_4 produced	43	114	24	12	16

(SOURCE: 15, p. 4-45)

TABLE 4-3

ESTIMATES OF AMMONIA AND HYDROGEN CYANIDE FROM COAL REFINING

Description	Appalachian region	Eastern interior region	Fort Union region	Powder River region	Four Corners region
Bi-Gas process, tons per day					
Nitrogen to plant	493	726	779	883	864
Ammonia produced	180	249	275	306	298
Wastewater stream	49,709	48,789	48,889	47,459	51,500
Ammonia in wastewater @ 50 ppm	2.5	2.4	2.4	2.4	2.6
Recoverable ammonia	178	247	273	304	295
Solvent-Refined process, tons per day					
Nitrogen to SRC (coal only)	517	721	722	105	876
Nitrogen to gasifier (coal only)	70	142	206	[a]	152
Nitrogen in gasifier effluent	183	236	313	291	730
Ammonia in gasifier effluent	56	72	95	83	222
Separator water	3,242	8,957	44,590	20.348	14,458
Ammonia remaining in separator water @ 50 ppm	0.16	0.45	2.2	1.0	0.72
Recoverable ammonia	56	72	93	37	221
HCN estimates (basis 4% of NH_3)					
Bi-Gas, tons per day	11	16	17	19	19
Bi-Gas, ppm	221	323	348	400	369
SRC, tons per day	4	5	6	6	14
SRC, ppm	1,230	558	135	295	968

[a] No coal to gasifier in this case.

although produced in large quantities during gasification, is principally emitted because of incomplete combustion in auxiliary facilities.

Other gaseous compounds of interest are carbonyls, hydrogen chloride, hydrogen fluoride, trace elements that vaporize, and trace organics. The latter two groups of pollutants will be discussed elsewhere. Although these compounds should be removed in the processing steps, they may be discharged to the air due to fugitive emissions, incomplete stripping of the process exhaust streams, evaporation from disposal ponds, and stripping in cooling towers.

There is the possibility of iron carbonyl formation as a result of the reaction between carbon monoxide and carbon steel pipe at high pressures and low temperatures. The extent of their reaction is not known. During methanation of synthesis gas nickel carbonyl may possibly be formed under certain upset conditions. There is a need to determine the conditions under which nickel carbonyl is formed at the methanator (51).

The possible environmental impacts identified in this report to this point have been very limited and idealized. Potential pollutants other than those previously mentioned may exist. The exact pollutants will be determined by the coal composition and the operating conditions of the reactor. The fate of these species will be determined by the product processing steps, control and treatment facilities, and the likelihood of fugitive emissions.

Through technologies applied before, during, and after conversion, the largest portion (50 to 98 percent) of the sulfur in coal can be recovered. Lesser amounts are retained in the ash, tars, chars, or liquefaction solids, and only a small fraction is emitted to the environment.

No reports of nitrogen oxide emission levels or control and treatment processes designed specifically for conversion technologies were located. However, some techniques developed for nitrogen oxide control from coal combustion plants may be applicable to conversion plants. Nitrogen emissions (primarily nitrogen oxides, ammonia, and hydrogen cyanide) may be reduced by appropriate combustion techniques, operating modifications, or removal processes, e.g., gas scrubbing. Both ammonia and hydrogen cyanide retained in wastewaters are accessible to technologies used for treating industrial wastewaters (biodegradation, nitrification, and chlorination). (15)

Particulates from coal conversion activities, as with any other industry using coal, pose a potentially serious emission problem and require treatment for control. After removal, they are disposed of as landfill or minefill, recycled as fuel, or in some instances sold as by-products. Minimizing fugitive emissions from processing equipment will require careful attention. Estimates of air emissions from a Lurgi Plant with pollution controls is presented in Table 4-4. (1)

4.3 WATER

Process wastewaters arise from moisture in the coal, water of constitution or decomposition, or water added for stoichiometric process requirements, by-product recovery, or gas scrubbing (15).

Process wastewater treatment and handling represent one of the major problem areas in meeting environmental requirements. Ideally, zero discharge could be accomplished by recycle/reuse processes proposed for most conversion designs because coal conversion processes are net consumers of water. However some aqueous discharges are probably inevitable because it is often technically or economically infeasible to recycle all wastewaters consumptively (78).

The principal source of water pollution in coal conversion is process waters, the composition of which is expected to be similar to that of ammonia liquor from coking industries. The liquid waste (gas liquor) contains, tar oils, phenols, ammonia, particulates, CO_2, H_2S, chloride, sulfate, cyanide and ferrocyanide. Reported trace

TABLE 4-4

YEARLY ESTIMATED EMISSIONS (TONS/YEAR) FROM WESCO COAL GASIFICATION (LURGI) PLANT WITH POLLUTION CONTROL

Item	Pollution control	SO_2	Particulates	COS	H_2S
Coal lock fan	Wet cyclone		0.4		
Ash lock fan	Wet cyclone		0.8		
Local vent[b]	None	7.8			Trace
Flare[b]	None	20.7			
Coal feed bin	Baghouse		3.9		
Coal lock	None			24	Trace
Boiler feed bin	Baghouse		1.0		
Steam boilers	Hot electrostatic precipitator and scrubber	2145	272		
Steam superheater	None	133	6.4		
Coal handling	Dust suppression		Trace		
Claus sulfur plant	Incineration and scrubber	480			
Stretford plant	Incineration and scrubber	63			
Gas liquor expansion gas	Incineration and scrubber	126			
Limestone handling	Baghouse		5.6		
Gas liquor vent gas	Incineration and scrubber	66			
Rectisol vent gas	Incineration	140			
Shift catalyst regeneration[c]	Scrubber	7.3			
Recovered hydrocarbons	Incineration and scrubber	73			
Total		3261.8	290.1	24	Trace

[a] Based on 7970 hr/year of full-capacity operation (N.B. -- 24 hr/day x 365 days/yr = 8760 hr/yr).
[b] During startup after periodic shutdowns.
[c] During catalyst regeneration only.

(SOURCE: 15, p. 4-49)

elements include antimony, arsenic, boron, bromine, cadmium, fluorine, lead, mercury and nickel (74).

Fugitive tars collected in wastewater contain a wide variety of organic compounds (Table 4-5), and wastewater particulates may collect and adsorb PAH. Of the water-soluble organics, phenols, and alcohols and their methylated derivatives appear to be important. Pyridines, quinolines, and indoles have also been identified in product wastewater. Miscellaneous materials in wastewater may include hydrogen fluoride, fatty acids, other trace organics, and trace elements (15).

These polluted waters will be primarily biotreated. However, some chemicals in ammonia liquor may be resistant to bacterial degradation, whereas other chemicals - including heavy metals, cyanides, halogenated compounds, phenols, mercaptans, guanidines, and thiourea - may be detrimental to bacterial survival.

Of the possible coal conversion emissions that differ from or greatly exceed those from existing sources, PAH, heterocyclic compounds, and trace elements stand out as a potential ecosystem hazards worthy of considerable attention (15).

4.4 SOLIDS

The potential environmental and economic consequences associated with the disposal of the solid wastes generated by even a single large-scale coal conversion facility is impressive because of the sheer magnitude of the wastes generated. Solid wastes from coal conversion processes may constitute 20 percent to 40 percent of the mass of the coal feed to the processes. A commercial gasification plant using 8 million tons of coal per year may produce 2.3 million tons of dry refuse (13,68).

Solid wastes from coal conversion processes include a large variety of materials. The major solid wastes are refuse from coal cleaning; ashes, slags and chars from the conversion processes; and

TABLE 4-5

COAL TAR CONSTITUENTS BY BOILING POINT

<100°C

Pentane
Hexane
Heptane
Cyclohexane
Butylene
Amylene
Hexene
Heptene
Cyclohexene
1,5-Butadiene
Crotonylene
Cyclopentadiene
Cyclohexadiene
Benzene
Acetone
Methylethyl ketone
Acetonitrile
Carbon disulfide
Methylmercaptan
Ethylmercaptan
Dimethyl sulfide
Diethyl sulfide
Thiophene

100 - 150°C

Octane
Methylcyclohexane
Dimethylcyclohexane
Nonaphthene
Toluene
o-Xylene
m-Xylene
p-Xylene
Ethylbenzene
Styrene
Pyrrole
Pyridine
2-Methylpyridine
3-Methylpyridine
4-Methylpyridine
2,6-Dimethylpyridine
Thiotoluene
Thioxene

150 - 200°C

Decane
Dicyclopentadiene
Hydrindene
Isopropylbenzene
o-Ethyltoluene
m-Ethyltoluene
p-Ethyltoluene
n-Propylbenzene
Mesitylene
Pseudocumene
Hemellitene
Cymene
Durene
Isodurene
Indene
2,7-Dimethylindene
3,6-Dimethylindene
Phenol
o-Cresol
Coumarone
Dimethylcoumarone
Aniline
Toluidine
2,3-Dimethylpyridine
2,4-Dimethylpyridine
2,5-Dimethylpyridine
3,4-Dimethylpyridine
Dimethylaniline
2,4,5-Trimethylpyridine
2,4,6-Trimethylpyridine
Benzonitrile

200 - 250°C

Naphthalene
Dihydronaphthalene
α-Methylnaphthalene
β-Methylnaphthalene
4,6-Dimethylindene
5,7-Dimethylindene
m-Cresol
p-Cresol
1,2,3-Xylenol
1,2,4-Xylenol
1,3,4-Xylenol
1,3,5-Xylenol
1,4,2-Xylenol
o-Ethylphenol
m-Ethylphenol
p-Ethylphenol
3-Methyl-5-ethylphenol
Isopseudocumenol
Durenol
2,2'-Dihydroxydiphenyl
Acetophenone
Benzoic acid
Dimethyl coumarone
1,2,3,4-Tetramethylpyridine
Quinoline
Isoquinoline
2-Methylquinoline
Thionaphthene

250 - 300°C

Diphenyl
3-Methyldiphenyl
2-Methyldiphenyl
4-Methyldiphenyl
4,4'-dimethyldiphenyl
3,4-Dimethyldiphenyl
Acenaphthene
1,2-Dimethylnaphthalene
1,6-Dimethylnaphthalene
1,7-Dimethylnaphthalene
2,6-Dimethylnaphthalene
2,7-Dimethylnaphthalene
2,3-Dimethylnaphthalene
2-Ethylnaphthalene
1-Ethylnaphthalene
1,2-Cyclopentanonaphthalene
Fluorene
α-Naphthol
β-Naphthol
Diphenylene oxide
α-Naphthofurane
β-Naphthofurane
1-Methyldiphenylene oxide
Indole
2-Methylindole
3-Methylindole
4-Methylindole
5-Methylindole
7-Methylindole
3-Methylquinoline
4-Methylquinoline
5-Methylquinoline
6-Methylquinoline
7-Methylquinoline
1-Methylisoquinoline
3-Methylisoquinoline
1,3-Dimethylisoquinoline
2,8-Dimethylquinoline
5,8-Dimethylquinoline
1-Naphthonitrile

Above 300°C

Nonadecane
Phenanthrene
Anthracene
2-Methylfluorene
3-Methylfluorene
Dihydroanthracene
4,5-Phenanthrylene methane
Chrysogen
Methylanthracene
Fluoranthene
Pyrene
Tetrahydrofluoranthrene
2,7-Dimethylanthracene
1,2-Benzfluorene
2,3-Benzfluorene
Chrysene
1,2-Benzanthracene
Naphthacene
Triphenylene
Perylene
1,2-Benzpyrene
Crackene
4,5-Benzpyrene
Picene
1,2-Benznaphthacene
Naphtho-2,3-1,2-anthracene
Acridine
Diphenylene sulfide
Benzerythrene
1-Metnylphenanthrene
3-Methylphenanthrene
9-Methylphenanthrene
Dibenzocoumarone
Carbazole
Benzacarbazole
Truxene
2-Methyldiphenylene oxide
2-Hydroxyfluorene
1,9-Benzoanthrene
2-Naphthylamine
Hydroacridine
2-Methylcarbazole
3-Methylcarbazole
2-Phenylnaphthalene
p-Phenylphenol
2-Hydroxydiphenylene oxide
Phenanthridene
2-Phenanthrol
1-Naphthylamine
2-Naphthonitrile

(SOURCE: 15, p. 4-107)

sludges from water cleanup. Refuse consists largely of rock, mineral matter and coal particles. Ash and slag consists of metallic oxides and trace element compounds. Coal and char particles contain organic and mineral materials. Wastewater treatment sludges, mixtures of coal tar residuals, sand, coal fines, and treatment by-products, may also contain untreated quantities of organics and other toxic materials (16).

Other solid effluents may include: spent catalysts, spent sulfur guard reactor absorbents, e.g., zinc sulfide, elemental sulfur from sulfur recovery processes; sludge from flue gas desulfurization, e.g., calcium sulfite and calcium sulfate; and sludge from evaporated aqueous process condensates. Fugitive dust from coal piles and limestone piles, ash from utility boilers, flitercake and evaporated solids from water regeneration chemicals may also be produced (1,13,16).

Estimates of solid wastes produced by coal conversion are presented in Tables 4-6 and 4-7.

Control methods exist for collecting coal dusts, fines, and airborne particulates. However, collected solid wastes stored in settling ponds may produce significant leachates about which little is known. Similarly, data describing leachate from unprotected storage areas have become available only recently (Table 4-8). Trace amounts of a very large number of elements appear in coal ash (Table 4-9), including some toxic elements such as mercury, cadmium, arsenic, selenium, and fluorine. However, these elements or their compounds are volatile and more likely to be associated with fly ash or airborne particulates (Table 4-10) (15).

Although some investigators maintain that ash and slag will be similar to ash from coal-fired power plants and require similar disposal means, this has not been demonstrated. The chemical form of the accessory elements in gasification ashes and slags is important but has not yet been investigated thoroughly. Data on fly ashes and

TABLE 4-6

ASH AND CHAR GENERATION IN GASIFIERS

Ash and char generation in gasifiers

	Bi-Gas		Synthane	CO_2 Acceptor	Hygas
Char, tons per day (metric tons per day)	None		4350 (3950) (dry) to utility boiler	5960 (5410) to regenerator	1667 (1512) (dry) char quenched and disposed. A slurry (25% solids) will be formed
Gasifier ash, slag [tons per day (metric tons per day)]	820 (740) (dry) granular slag. After quenching, 820 (740) H_2O will be added to form a slurry		1050 (950) ash leaving utility boiler	2795 (2536) carbonated dry ash and 2795 (2536) H_2O from regenerator (wet ash disposal)	Ash disposed of in char system
Plant size, 10^6 scfd (10^6 m^3/day at STP)	250 (7.1)		250 (7.1)	250 (7.1)	250 (7.1)
Coal feed rate to gasifier, tons per day (metric tons per day)	11,400 (10,340) (1.3% H_2O)		14,250 (12,930)	16,960 (15,390)	12,695 (11,516)
Coal type	W. Kentucky, No. 11		Pittsburgh seam	Lignite	Illinois No. 6
		Dried			
Percentage H_2O	8.4	1.3	2.5	0	0
Percentage ash	6.7	7.2	7.4	11.45	11.54
Percentage S	3.48	3.75	1.6	0.9	4.2

(SOURCE: 106, p. 4b.2.1-8)

TABLE 4-7

ESTIMATES OF SLAG, CHAR, AND ASH DISCHARGES, BI-GAS AND SRC PROCESSES (Tons Per Day)

Description	Appalachian region	Eastern interior region	Fort Union region	Powder River region	Four Corners region
		Bi-Gas			
Slag from gasifier	3,701	5,245	5,860	3,535	9,075
Char from scrubber	342	397	689	476	523
Refinery ash	715	1,013	1,137	686	1,761
Power plant ash	361	931	1,023	594	1,509
Slag quench water	14,798	20,979	23,493	14,149	36,286
Char scrubuer water	1,368	1,588	2,756	1,903	2,092
Makeup brine to slag quench	652	1,233	524	103	2,705
Dry ash disposal					
Wet slag (10% H_2O)	4,112	5,828	6,511	3,928	10,083
Wet char (10% H_2O)	380	441	766	529	581
Dry ash	1,346	1,944	2,160	1,280	3,270
Total solids discharge	5,838	8,213	9,437	5,737	13,934
Brine to evaporation	1,572	2,194	2,552	1,561	3,731
Wet ash disposal					
Ash slurry water	5,384	7,776	8,640	5,120	13,080
Makeup brine to slag quench and ash slurry	1,326	2,205	1,604	743	4,340
Wet ash (10% H_2O)	1,496	2,160	2,400	1,422	3,633
Total solids discharge	5,988	8,429	9,677	5,879	14,297
Brine to evaporation	2,095	2,950	3,392	2,059	5,003

(SOURCE: 15, p. 4-67)

TABLE 4-7
(Continued)

Description	Appalachian region	Eastern interior region	Fort Union region	Powder River region	Four Corners region
		SRC			
Slag from gasifier	4,439	6,311	7,448	4,255	10,953
Power plant ash	631	931	1,023	594	1,509
Slag quench water	17,756	25,244	29,792	17,020	43,812
Makeup brine to slag quench	2,219	3,155	3,724	2,128	5,477
Dry ash disposal					
Wet slag (10% H_2O)	4,932	7,012	8,276	4,728	12,170
Dry ash	631	931	1,023	594	1,509
Total solids discharge	5,563	7,943	9,299	5,322	13,679
Brine to evaporation	1,726	2,454	2,896	1,655	4,260
Wet ash disposal					
Ash slurry water	2,524	3,724	4,092	2,376	6,036
Makeup brine to slag quench and ash slurry	2,535	3,620	4,236	2,425	6,231
Wet ash (10% H_2O)	701	1,034	1,137	660	1,677
Total solids discharge	5,633	8,046	9,413	5,388	13,847
Brine to evaporation	1,972	2,816	3,294	1,886	4,846

TABLE 4-8

CHARACTERISTICS OF COAL PILE DRAINAGE

Constituents	Concentration (mg/liter)	
	Plant J	Plant L
Acidity (total), as $CaCO_3$	1700	270
Calcium	240	350
Chemical oxygen demand	9	
Chloride	0	
Conductance, µmho/cm	2400	2100
Dissolved solids (total)	3200	1500
Hardness, as $CaCO_3$	600	980
Magnesium	1.2	0.023
pH, unit	2.9	2.9
Potassium		0.5
Silicon (dissolved)	91	
Sodium		4.1
Sulfate	2600	
Suspended solids (total)	550	810
Turbidity, JTU	300	
Aluminum	190	
Arsenic	0.01	0.009
Barium		0.1
Beryllium		<0.01
Cadmium	<0.001	0.006
Chromium	<0.005	<0.005
Copper	0.56	0.18
Iron	510	830
Lead	<0.01	0.023
Manganese	27	110
Mercury	<0.0002	0.027
Nickel	1.7	0.32
Selenium	0.03	0.003
Titanium	<1	
Zinc	3.7	1.0

(SOURCE: 22, p. 34)

TABLE 4-9

MINOR TRACE ELEMENTS

Element	In feed coal		In condensate	
	(ppm)	(lb/day)	(ppm)[a]	(lb/day)
Boron	165	4700		
Barium	100	2900	0.13	0.2
Zinc	44	1250	0.06	1
Vanadium	35	1000	0.003	0.05
Lithium	25	710		
Chromium	22	620	0.006	0.1
Nickel	14	400	0.03	0.5
Germanium	12	340	0.04	0.6
Copper	12	340	0.02	0.3
Manganese	10	290	0.04	0.6
Molybdenum	8.2	230		
Yttrium	7.7	220		
Lanthanum	5.1	150		
Uranium	5	140		
Cobalt	3.8	110	0.002	0.03
Tin	1.5	43	0.02	0.3

(SOURCE: 79, p. 63)

TABLE 4-10

RANGE IN AMOUNT OF TRACE ELEMENTS PRESENT IN COAL ASHES (ppm)

Element	Anthracites			Lignites and Subbituminous		
	Max	Min	Average(5)	Max	Min	Average(13)
Ag	1	1	*b*	50	1	*b*
B	130	63	90	1,900	320	1020
Ba	1340	540	866	13,900	550	5027
Be	11	6	9	28	1	6
Co	165	10	81(4)	310	11	45
Cr	395	210	304	140	11	54
Cu	540	96	405	3,020	58	655
Ga	71	30	42	30	10	23(12)
Ge	20	20	*b*	100	20	*b*
La	220	115	142	90	34	62
Mn	365	58	270	1,030	310	688
Ni	320	125	220	420	20	129(8)
Pb	120	41	81	165	20	60
Sc	82	50	61	58	2	18(10)
Sn	4250	19	962	660	10	156
Sr	340	80	177	8,000	230	4660
V	310	210	248	250	20	125
Y	120	70	106	120	21	51
Yb	12	5	8	10	2	4
Zn	350	155	*b*	320	50	*b*
Zr	1200	370	688	490	100	245

[a] Figures in parentheses indicate the number of samples used to compute average values.

[b] Insufficient figures to compute an average value.

(SOURCE: 15, p.4-71)

slags produced in coal-fired furnaces may not be pertinent, because gasification ashes and liquefaction residues are produced under different conditions, namely at high temperatures and pressures and usually in a reducing atmosphere rather than in an oxidizing one. Significant differences in mineralogy and chemical form of produced species may affect the solubility of accessory elements in the ash and thus affect their potential as pollutants (1,68).

Analysis of the chemical and mineralogical characteristics of a Lurgi gasification ash and an H-Coal liquefaction residue from the Illinois Herrin (No. 6) coal member, indicated that of the approximately 60 chemical constituents measured in the raw Lurgi ash, 15 were found to be soluble enough to exceed recommended water quality levels. Over the pH range 3-10, nine of the constituents--B, Ca, Cd, K, Mn, NH_4, Pb, SO_4, and Sb--exceeded the recommended levels in all solutions, as shown in Table 4-11.

The investigators also found indications that the use of alkaline conversion ashes to neutralize acid mine refuse or disposal of the ash and refuse together as landfill in strip mines may actually aggravate environmental hazards. Accessory elements in the ash and refuse may be extracted by the acid solution and these trace elements may actually catalyze the further formation of acid (68).

Although it is generally assumed that coked or ashed solids from the conversion reactors are essentially inert, the real pollution potential of these solids is yet to be determined. Char may adsorb oil and trace metals from cooling and process waters; desorption may occur in the char disposal or utilization sites (51).

The problems associated with disposal of solid waste must be resolved to minimize environmental degradation. Landfilling and minefilling techniques will require additional sophistication to prevent contamination of thte surrounding area.

Subsidence, the gradual settling of landfill materials, is another problem.

TABLE 4-11

ELEMENTS EXCEEDING RECOMMENDED WATER QUALITY LEVELS

	LURGI Ash Solubility		H-Coal Residue Solubility		
Constituent	pH 3 (mg/l)	pH 8 (mg/l)	pH 3 (mg/l)	pH 8 (mg/l)	Recommended Levels (mg/l)
Al	132.	<0.5	5.5	<0.5	0.10
B[a]	5.5	4.0	13.6	13.0	0.75
Ca[a]	570.	290.	497.	175.	50.
Cd[a]	0.06	0.02	--	--	.01
Cr	0.12	<0.02	--	--	0.05
Co	0.19	<0.10	--	--	0.05
Cu	0.75	0.01	--	--	0.20
F	--	--	0.86	1.15	1.00
Fe	560.	0.06	31.50	<0.10	0.30
K[a]	26.	42.	--	--	5.00
Mn[a]	3.80	0.45	2.68	0.04	0.05
NH_4[a]	11.	17.	8.	6.	0.02
Pb[a]	0.20	0.10	0.25	<0.10	0.03
SO_4[a]	338.	820.	--	--	250.
Sb[a]	0.60	0.20	--	--	0.05
Zn	17.00	0.12	0.27	0.01	0.20

[a] Highest pollution potential

(SOURCE: 68, p. 513)

4.5 ORGANICS

Coal-derived organic compounds that can be emitted from conversion process streams have not yet been completely characterized. It has been estimated that, of 10,000 compounds in coal tar and hydrogenation products, only 1000 have been identified. This is partly because the amounts and characteristics of the organics are variable, influenced by both the coal characteristics and the process operating conditions. Listings of identified and potential organic constituents, and various characteristics are presented in Appendix C (15).

Processing conditions will affect organic effluents from coal conversion since the two major sources of trace organics are those originally present in the coal and released through volatilization or leaching, and those formed by chemical reaction. Organic compounds that may be present in the gas, liquid, and solid waste streams from coal conversion activities include naphtha, coal tar, light and heavy oil, BTX (benzene, toluene, and xylene), and product gases (15,78).

The coal gasifier output may contain all of the products commonly associated with pyrolysis, carbonization, and coking of coals in addition to oxygenated products associated with partial combustion. Several classes of compounds may be present. Various heavier organic compounds may be classified as tar (including phenols, cresols, pyridines, anilines, catechols), intermediate and high-boiling aromatics (naphthalenes), saturates, olefins, and thiophenes. Another group of organic compounds might be designated light oil and/or naphtha, including BTX, naphthalene, thiophene and condensable light hydrocarbons and disulfide carbon. (78)

Two major classes of organic compounds associated with coal liquefaction systems have been identified: the aliphatic and the aromatic. Among the aliphatics, there are light-chained compounds (e.g., methane through dodecane) and all stereoisomers plus the alkenes and alkynes of the above, and the heavy-chained aliphatics.

Among the aromatic compounds are benzene, naphthalenes, aromatic amines, and polynuclear aza-heterocyclics (16).

The primary hazards arising from organic wastes are due to fugitive emissions and disposal of the waste in evaporation ponds for contaminated wastewater streams. These waste ponds will contain a mixture of hydrocarbons, ammonia, phenols, hydrogen sulfide and trace elements. Exact composition of the wastes and associated hazards will depend on the wastewater treatment methods employed. Complete characterization will have to await the availability of such wastes themselves from pilot projects or commercial operations.

Bottom sludges from evaporation ponds may contain significant quantities of organics and pose handling and disposal hazards. The formation of toxic gases or the evaporation of harmful materials from evaporation ponds may also present environmental hazards. Metals may catalyze reactions and microorganisms may act as biological mediators, further complicating environmental characterization, measurement and monitoring.

An important aspect of assessing potential problems resulting from the disposal of hazardous organics concerns their breakdown in the environment. Virtually all hydrocarbons of the aliphatic, olefinic, aromatic or naphthenic series may be oxidized by microbes. However, the ease with which these oxidations are accomplished, and the potential environmental impacts of the products of incomplete oxidation will vary by pollutant (122).

Possibly the most health-endangering coal-derived compounds are polycyclic aromatic hydrocarbons (PAH). Workers exposed to high levels of PAH-containing coal volatiles show an increased incidence of skin and lung cancers.

Coal-derived liquids contain a high percentage of aromatic and polyaromatic compounds, although, as in petroleum, saturated paraffins dominate the low-boiling fractions.

Information concerning atmospheric emission of PAH from coal conversion processes is scarce. However, coal burning studies indicate that the majority of PAH is adsorbed on particulate matter; control of air emissions by particulate collection would be expected to remove most PAH.

Humans are most likely to encounter PAH by accidental ingestion, inhalation, or skin contact. Laboratory animal studies indicate that skin contact may be considerably more hazardous than ingestion. Aromatic hydrocarbons condensed on the exterior surfaces of equipment and structures may be a significant source of aromatic hydrocarbons contamination, but as yet little is known on the subject. (15,78).

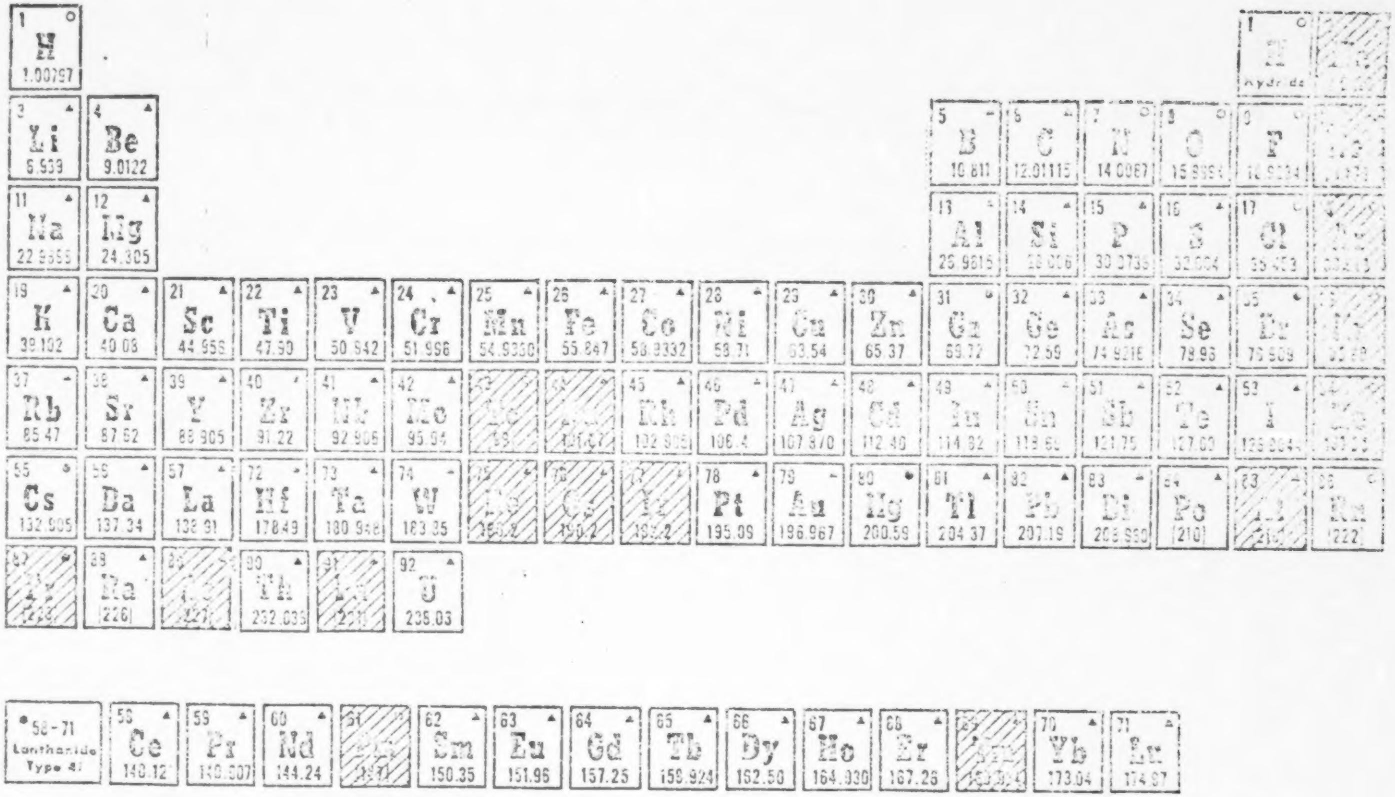
Limited information is available concerning the bioenvironmental effects of heterocyclic compounds; however, the behavior of hetercyclics may be similar to that of PAH.

4.6 TRACE ELEMENTS

Due to its organic origin and its intimate commixture with crustal formations, coal contains a large number of elements in minor or trace quantities. Of the 92 known non-transuranic elements, only 14 (shown in Figure 4-1) have not yet been found in coal. Trace element content in American coals is presented in Tables 4-12, 4-13, and 4-14. Elemental and inorganic compounds identified in effluents from coal gasification and liquefaction are compared with trace constituents from other energy-related processes in Appendix C. (86)

Although several potentially hazardous pollutants exist in coal only in trace amounts, conversion facilities will be processing 15 to 25 thousand tons of coal per day, which makes it necessary to investigate trace element species during gasification.

It has been estimated that a conversion facility producing 15 to 20 trillion cubic feet of SNG per year could result in the production of the following trace elements in pounds per year: arsenic, 28 million; cadmium, 2 million; lead, 20 million; manganese, 108 million;


1 H 1.00797
1 H Hydride
3 Li 6.939
4 Be 9.0122
5 B 10.811
6 C 12.01115
7 N 14.0067
8 O 15.9994
9 F 18.9984
11 Na 22.9898
12 Mg 24.305
13 Al 26.9815
14 Si 28.086
15 P 30.9738
16 S 32.064
17 Cl 35.453
19 K 39.102
20 Ca 40.08
21 Sc 44.956
22 Ti 47.90
23 V 50.942
24 Cr 51.996
25 Mn 54.9380
26 Fe 55.847
27 Co 58.9332
28 Ni 58.71
29 Cu 63.54
30 Zn 65.37
31 Ga 69.72
32 Ge 72.59
33 As 74.9216
34 Se 78.96
35 Br 79.909
37 Rb 85.47
38 Sr 87.62
39 Y 88.905
40 Zr 91.22
41 Nb 92.906
42 Mo 95.94
45 Rh 102.905
46 Pd 106.4
47 Ag 107.870
48 Cd 112.40
49 In 114.82
50 Sn 118.69
51 Sb 121.75
52 Te 127.60
53 I 126.9044
55 Cs 132.905
56 Ba 137.34
57 La 138.91
72 Hf 178.49
73 Ta 180.948
74 W 183.85
78 Pt 195.09
79 Au 196.967
80 Hg 200.59
81 Tl 204.37
82 Pb 207.19
83 Bi 208.980
84 Po (210)
86 Rn (222)
88 Ra (226)
90 Th 232.038
92 U 238.03
58-71 Lanthanide Type 4f
58 Ce 140.12
59 Pr 140.907
60 Nd 144.24
62 Sm 150.35
63 Eu 151.96
64 Gd 157.25
65 Tb 158.924
66 Dy 162.50
67 Ho 164.930
68 Er 167.26
70 Yb 173.04
71 Lu 174.97

(SOURCE: 86, p. 419)

FIGURE 4-1
PERIODIC TABLE OF THE ELEMENTS

TABLE 4-12

MEAN ANALYTICAL VALUES FOR 101 COALS

Constituent	Mean	Standard deviation	Min	Max
Arsenic, ppm	14.02	17.70	0.50	93.00
Boron, ppm	102.21	54.65	5.00	224.00
Beryllium, ppm	1.61	0.82	0.20	4.00
Bromine, ppm	15.42	5.92	4.00	52.00
Cadmium, ppm	2.52	7.60	0.10	65.00
Cobalt, ppm	9.57	7.26	1.00	43.00
Chromium, ppm	13.75	7.26	4.00	54.00
Copper, ppm	15.16	8.12	5.00	61.00
Fluorine, ppm	60.94	20.99	25.00	143.00
Gallium, ppm	3.12	1.06	1.10	7.50
Germanium, ppm	6.59	6.71	1.00	43.00
Mercury, ppm	0.20	0.20	0.02	1.60
Manganese, ppm	49.40	40.15	6.00	181.00
Molybdenum, ppm	7.54	5.96	1.00	30.00
Nickel, ppm	21.07	12.35	3.00	80.00
Phosphorus, ppm	71.10	72.81	5.00	400.00
Lead, ppm	34.78	43.69	4.00	218.00
Antimony, ppm	1.26	1.32	0.20	8.90
Selenium, ppm	2.08	1.10	0.45	7.70
Tin, ppm	4.79	6.15	1.00	51.00
Vanadium, ppm	32.71	12.03	11.00	78.00
Zinc, ppm	272.29	694.23	6.00	5,350.00
Zirconium, ppm	72.46	57.78	8.00	133.00
Aluminum, %	1.29	0.45	0.43	3.04
Calcium, %	0.77	0.55	0.05	2.67
Chlorine, %	0.14	0.14	0.01	0.54
Iron, %	1.92	0.79	0.34	4.32
Potassium, %	0.16	0.06	0.02	0.43
Magnesium, %	0.05	0.04	0.01	0.25
Sodium, %	0.05	0.04	0.00	0.20
Silicon, %	2.49	0.80	0.58	6.09
Titanium, %	0.07	0.02	0.02	0.15
Organic sulfur, %	1.41	0.65	0.31	3.09
Pyritic sulfur, %	1.76	0.86	0.06	3.78
Sulfate sulfur, %	0.10	0.19	0.01	1.06
Total sulfur, %	3.27	1.35	0.42	6.47
Sulfur by X-ray fluorescence, %	2.91	1.24	0.54	5.40
Air-dry loss, %	7.70	3.47	1.40	16.70
Moisture, %	9.05	5.05	0.01	20.70
Volatile matter, %	39.70	4.27	18.90	52.70
Fixed carbon, %	48.82	4.95	34.60	65.40
Ash, %	11.44	2.89	2.20	25.80
Btu/lb	12,748.91	464.50	11,562.00	14,362.00
Carbon, %	70.28	3.87	55.23	80.14
Hydrogen, %	4.95	0.31	4.03	5.79
Nitrogen, %	1.30	0.22	0.78	1.84
Oxygen, %	8.68	2.44	4.15	16.03
High-temperature ash, %	11.41	2.95	3.28	25.85
Low-temperature ash, %	15.28	4.04	3.82	31.70

(SOURCE: 105, p. 18)

TABLE 4-13

TRACE ELEMENT CONTENT OF AMERICAN COALS (PPM IN COAL)

Element	Region			
	Northern Great Plains	Western Interior	Eastern Interior	Appalachian
Beryllium	1.5	1.1	2.5	2.5
Boron	116	33	96	25
Titanium	591	250	450	340
Vanadium	16	18	35	21
Chromium	7	13	20	13
Cobalt	2.7	4.6	3.8	5.1
Nickel	7.2	14	15	14
Copper	15	11	11	15
Zinc	59	108	44	7.6
Gallium	5.5	2.0	4.1	4.9
Germanium	1.6	5.9	13	5.8
Molybdenum	1.7	3.1	4.3	3.5
Tin	0.9	1.3	1.5	0.4
Yttrium	13	7.4	7.7	14
Lanthanum	9.5	6.5	5.1	9.4

(SOURCE: 123, p. 11)

TABLE 4-14

DISTRIBUTION OF ENVIRONMENTALLY HAZARDOUS TRACE ELEMENTS (PPM IN COAL)

Element	Region			
	Powder River Basin	Western Interior	Eastern Interior	Appalachian
Antimony	0.67	3.5	1.3	1.2
Arsenic	3	16	14	18
Beryllium	0.7	2	1.8	2.0
Cadmium	2.1	20	2.3	0.2
Mercury	0.1	0.13	0.19	0.16
Lead	7.2		34	12
Selenium	0.73	5.7	2.5	5.1
Zinc	33		250	13

(SOURCE: 123, p. 12)

mercury, 400 thousand; and nickel, 30 million. These quantities could be emitted in concentrated areas (101)

Trace elements may be in the elemental form or combined in organic or inorganic compounds. In general, Ge, Be, Sb and Br have high organic associations in coal; Ni, Cu, Cr and Hg tend to be present in both organic and inorganic combinations; and Zn, Cd, As, and Fe are primarily associated with coal mineral matter. Several investigations have also indicated that pollution in coal combustion and conversion will for the most part be associated with the inorganic matter in coal. It is possible that enhanced volatility of an organically associated trace element could lead to its concentration in a process stream. (85)

It is obvious that all trace elements entering a plant must also leave via effluents or product streams. However fates of trace elements in coal conversion are not completely known. Trace element pathways may include adsorption on particulate matter, inclusion in condensates, deposition on equipment surfaces, inclusion in by-products and final products, and emission as fugitive pollutants, thus requiring development of a variety of suitable control technologies (15).

The fate of trace elements in coal liquefaction or gasification can be very different from that experienced in conventional coal fired furnaces. One reason is that the conversion operations take place in a reducing atmosphere, whereas in combustion the conditions are always oxidizing. This affects the resultant oxidation state and the subsequent tendency of the elements to combine or dissolve in the major ash components. Furthermore the reducing atmosphere may form hydrides, carbonyls or sulfides which may be more volatile.

Many of the trace elements volatilize to a small or large extent during processing, and many of the volatile components can be highly toxic. This is especially true for mercury, selenium, arsenic, molybdenum, lead, cadmium, beryllium, and fluorine. Beryllium, mercury and lead do not form gaseous hydrides, will condense on cooling, and will very likely be removed by the aqueous condensates formed on gas cooling and/or purification. Arsenic, antimony, and selenium have lower volatility but can form gaseous (covalent) hydrides: arsine, stibine, and hydrogen selenide. (89)

Consideration must also be given to trace metals that are not volatilized and leave in the solid effluents from the plant, e.g., slag, char, ash, and sludge. Undesirable elements might be leached from the solid wastes if they are handled as a water slurry or when disposed of in landfills or mines. Sufficient information is not now available to assess potential problems.

Other possible sources of trace element emissions from the plant need to be evaluated. Additives such as chromates may be used in the cooling water circuit and appear in the blowdown stream. Trace elements may be present in chemical purge streams such as from acid gas removal systems where arsenates etc. may be used as additives, or from absorption/oxidation sulfur plants using catalysts such as vanadates. Catalysts can contribute nickel, cobalt, molbydenum, chromium and zinc. (15,89)

Potential losses of trace elements in the Hygas, Synthane and COED gasification processes are presented in Tables 4-15, 4-16, and 4-17. Trace elements from coal conversion and use pose at least as serious a potential bioenvironmental hazard as do organic effluents. Because some trace elements are resistant to metabolic detoxification and all are nondegradable, they can accumulate in biota. Also, once released, they persist in the environment indefinitely. Some trace metals already exist in the environment at maximum or near-maximum permissible levels.

Lead, mercury, arsenic, vanadium, selenium, nickel, and possibly cadmium and fluoride may be important environmentally. Lead, mercury, and cadmium are particularly important because they are capable of long distance transport (15).

TABLE 4-15

TRACE ELEMENT CONCENTRATION OF PITTSBURGH NO. 8 BITUMINOUS COAL AT VARIOUS STAGES OF GASIFICATION

	Feed Coal	After Pretreat	After Hydro-Gasifier	After Electro Thermal Gasifier	% Overall Loss for Element
Max. Temp. of Treat, °C	-	430	650	1000	
Element:	ppm				
Hg	0.27	0.19	0.06	0.01	96
Se	1.7	1.0	0.65	0.44	74
As	9.6	7.5	5.1	3.4	65
Te	0.11	0.07	0.05	0.04	64
Pb	5.9	4.4	3.3	2.2	63
Cd	0.78	0.59	0.41	0.30	62
Sb	0.15	0.13	0.12	0.10	33
V	33	36	30	23	30
Ni	12	11	10	9.1	24
Be	0.92	1.0	0.94	0.75	18
Cr	15	17	16	15	0

(SOURCE: 89, p. 108)

TABLE 4-16

POTENTIALLY HAZARDOUS TRACE ELEMENTS

Element	In feed coal (ppm)	To gasifier (lb/day)	Condensate[a] (ppm)	Raw gas[a,b] (ppm)	Tar[a] (ppm)
Beryllium	2	60			
Fluorine	85	2430			
Arsenic	31	890	0.03 (0.5)		0.7 (0.7)
Selenium	2.2	65	0.36 (6)		
Cadmium	0.14	4			
Mercury	0.2	6		0.0001[c] (0.04)	0.003 (0.003)
Lead	7.7	220			
HCN				20[c] (1000)	

[a] Numbers in parentheses indicate quantities in pounds per day appearing in design streams.
[b] No mercury or HCN detected in product gas.
[c] Units as given in Forney and Magee 1972.

(SOURCE: 79, p. 64)

TABLE 4-17

TRACE ELEMENT RESULTS (PPM) FOR THE COED PROCESS

Element	Feed	Raw oil	Filter cake	Syncrude	2nd-stage liquor	1st-stage liquor	Char	Fines, oil	Fines, cyclone	Filtrate
Al	5,000	5,000	10,000	90	70	4	10,000	100	30	2,000
As	3	3	7	2	0.7	0.01	10	2	1	2
B	200	200	200	4	10	3	300	3	20	100
Ba	5	1	10	1	3	<0.5	50	2	0.1	1
Bi	<0.3	<0.3	<0.3	<0.3	<0.3	0.3	3	<0.3	<0.3	<0.3
Br	<0.2	0.7	<0.2	<0.1	<0.3	<0.3	<4	<0.3	3	0.1
Ca	1,000	3,000	3,000	30	100	500	10,000	100	200	1,000
Cd	<0.3	<0.3	<0.3	<0.3	<0.3	<0.3	≤2	<0.3	<0.3	<0.3
Cl	20	100	20	3	1	10	300	30	10	20
Co	1	0.2	2	0.1	0.1	1	5	0.4	<0.1	0.3
Cr	5	2	2	0.7	1	1	300	5	2	2
Cs	<0.1	1	0.5	0.2	0.2	5	1	<0.5	<0.2	0.5
Cu	3	2	10	0.3	0.3	5	150	1	0.4	2
F	4	2	10	1	2	<0.5	50	3	0.2	2
Fe	10,000	7,000	10,000	400	500	300	20,000	3,000	20	15,000
Ga	1	0.5	2	0.2	0.1	<0.1	4	0.3	<0.1	0.2
Ge	1	0.8	1	<0.7	<0.5	<0.5	3	<0.5	<0.5	1
K	200	250	500	10	100	4	3,200	100	10	200
La	10	1	5	1	1	0.1	10	5	0.1	2
Mg	60	200	500	20	20	60	4,000	50	20	500
Mn	5	5	10	0.4	0.6	7	100	5	0.4	2
Mo	5	0.5	20	0.7	<0.5	0.8	7	<0.5	5	<0.5
Na	50	100	500	10	30	10	≤500	50	300	50
Nb	2	0.1	0.4	0.3	0.3	<0.1	3	<0.5	0.5	0.2
Nd	10	2	5	1	2	1	5	3	0.5	3
Ni	30	70	50	4	10	100	40	50	10	7
P	20	10	70	3	5	0.2	200	20	2	10
Pb	3	1	10	1	2	0.1	30	2	<0.1	1
Pr	2	0.5	3	0.4	0.3	0.4	3	[illegible]	0.1	1
Rb	1	0.5	2	0.2	0.2	0.02	10	0.5	<0.1	0.3
Sb	0.5	<0.2	0.1	<0.1	<0.1	<0.1	<2	<0.1	<0.2	<0.2
Sc	3	1	1	0.4	0.5	<0.5	10	[illegible]	<0.5	[illegible]
Se	0.3	<0.1	0.4	≤0.1	<0.1	0.2	3	1	2	0.1
Si	3,000	7,000	15,000	1,000	2,000	30	30,000	8,000	1,000	15,000
Sn	<0.3	<0.3	≤0.3	<0.3	<0.1	<0.1	<3	<0.5	0.6	<0.3
Sr	10	5	30	10	4	0.3	60	10	<0.5	10
Ta	≤1	≤1	≤1	≤0.5	≤0.5	≤1	≤3	≤1	≤3	≤1
Te	<0.5	<0.5	<0.5	<0.5	<0.5	<0.5	<3	<0.5	<0.5	<0.5
Th	0.7	0.2	0.6	0.8	0.4	<0.1	4	0.7	<0.1	0.2
Ti	200	50	100	20	20	<1	2,500	70	<1	50
Tl	2	0.5	3	0.5	1	0.3	<3	0.3	<0.5	0.5
U	2	0.7	2	1	0.5	<0.1	3	<0.5	<0.5	0.6
V	50	5	30	2	2	0.1	300	5	0.1	15
W	3	<0.5	2	0.4	0.4	<0.5	<5	<0.5	<0.5	<0.5
Y	7	1	5	1	1	0.5	25	3	<0.3	2
Zn	10	3	10	2	1	3	400	1	1	4
Zr	10	3	20	2	3	<0.5	30	10	3	1

(SOURCE: 106, p. 38)

Although considerable data is available concerning the acute health effects from trace elements, little is known about low-level chronic effects to be expected from the amounts and forms of these elements as they may be emitted from coal conversion operations. Lead, chromium, manganese, arsenic, fluoride, nickel, cadmium, zinc, and copper may pose human health hazards.

4.7 PRODUCTS AND BY-PRODUCTS

A full slate of products, extending from fuel gas to ash can be obtained from gasification or liquefaction processes; the relative quantities of products varies largely as a function of process temperature and pressure, and feed coal. Although the types of impurities in these streams are expected to be similar (including sulfur and nitrogen compounds, heavy metals and particulates), little information exists as to how these contaminants will be distributed throughout the products and recovered by-products. Many contaminants will probably appear in the crude by-products and will have to be removed for environmental protection. (74).

Product components derived from the H-Coal process using Illinois No. 6 Coal are presented in Table 4-18.

Present information indicates that coal liquefaction products boiling in the gasoline ranges are essentially indistinguishable from highly aromatic petroleum products in the same boiling range; therefore, no new hazard is posed to the consumer. (1) However, in contrast to petroleum, synthetic crude oils can possess higher levels of acidic components such as phenols and cresols some of which appear in the low-boiling distillate.

With only slight modification, standard oil-refining techniques should be applicable to synthetic crude oils. Although the composition of refined products from syncrudes will undoubtedly depend on the starting materials, the concentration of PAH in the heavier fractions is expected to exceed that of petroleum products. (15) The distillate

TABLE 4-18

INSPECTION OF PRODUCTS FROM ILLINOIS NO. 6 COAL

Compound	Component	Weight percent	Total weight percent
	C_4 - 400°F fraction		
Saturated compounds	nC_4	0.10	
	iC_5	0.20	
	nC_5	0.69	
	C_6 - C_{12}	11	11.99
Alkyl benzenes	C_6 - C_{12}	17.55	17.55
Saturated naphthenes	Monocycloparaffins	42.64	
	Dicycloparaffins	8.50	
	Tricycloparaffins	0.19	51.33
Unsaturated naphthenes	Monocycloparaffins	5.32	
	Dicycloparaffins	4.98	
	Tricycloparaffins	0.90	11.20
Other compounds	Indans	6.44	
	Naphthalenes	0.59	
	Phenols (mol. wt) - 108, 122, 136, 150	1.0	7.93
			100.00
	400 - 650°F fraction		
Saturated compounds	n-paraffins	4.8	
	i-paraffins	1.7	
	Monocycloparaffins	14.0	
	Dicycloparaffins	7.9	
	Tricycloparaffins	2.6	31.0
Unsaturated nonaromatic	Monocycloparaffins	4.3	4.3
Aromatic compounds	Alkyl benzenes	12.6	
	Indans & tetralins	30.8	
	Indenes	5.7	
	Naphthalenes	0.2	
	Naphthalenes	3.5	
	Acenaphthenes (C_nH_{2n-14})	4.0	
	Acenaphthenes (C_nH_{2n-16})	2.2	
	Tricyclics (C_nH_{2n-18})	0.4	59.6
Other compounds	Phenols (mol. wt) - 108, 122, 136, 150, 164, 178	2.0	
	Other nonhydrocarbons	3.10	5.10
			100.00

(SOURCE: 76, p. 88)

TABLE 4-18
(Continued)

Compound	Component	Weight percent	Total weight percent
	650 - 919°F fraction		
Saturated compounds	Paraffins	1.4	
	Monocycloparaffins	3.1	
	Bicycloparaffins	0.6	
	Tricycloparaffins	0.7	
	Tetracycloparaffins	0.4	
	Pentacycloparaffins	0.2	
	Hexacycloparaffins	0.1	
	Phenyls	0.3	
			6.8
Unsaturated nonaromatic	Paraffins	0.0	
	Monocycloparaffins	0.5	
	Bicycloparaffins	0.3	
	Tricycloparaffins	0.2	
	Tetracycloparaffins	0.2	
	Pentacycloparaffins	0.1	
	Hexacycloparaffins	0.1	
	Phenyls	0.2	
			1.6
Other compounds	Alkyl benzenes	3.0	
	Indans and/or tetralins	0.5	
	Other aromatics[a]	72.8	
	Phenolic compounds	1.5	
	Other nonhydrocarbons	13.8	
			91.6
			100.00

[a] An approximate breakdown of aromatic-type compounds is:

Component type	Millimoles per 100 g
Naphthalenes	93.4
Phenanthrenes	91.1
Chrysenes	21.9
1-2 Benzanthracenes 3-4 Benzphenanthrenes	14.6
Pyrenes	15.4
6-Ring compounds	5.1

fuel oils (boiling between 200 and 540°C) produced in coal hydrogenation (and coal pyrolysis) will contain relatively high concentrations of polynuclear aromatics and probably will be more carcinogenic than typical petroleum fractions in the same boiling range. Concentrations of polynuclear aromation are usually 10-100 times the level found in smoke; and benzo (a) pyrene concentrations range from 40-50 ppm in coal derived products as compared to 1 ppm in condensed tobacco smoke. (1,16)

Quantitites of PAH in a coal-derived liquefaction products are presented in Tables 4-19, 4-20, and 4-21.

Liquefaction products can be refined to meet desired specifications although combustion tests have not yet established how severe the refining treatment must be to produce products meeting boiler fuel and turbine fuel emission specifications. The most difficult problem may be the reduction of the nitrogen content to a level adequate to meet NO_x emission standards. (1)

Examples of organic sulfur compounds present in coal hydrogenation products are presented in Table 4-22.

4.8 TRANSIENT POLLUTANTS

Waste streams produced during normal process operation are expected and provisions are made for their disposition on a continuous basis. Consideration must also be given to transient pollutants generated as a result of intermittent occurrences. These releases may be unplanned or accidental, caused by leaks, spills, upsets, startups, shutdowns, power failure, process equipment failures, slugging, surging, and overloading. They may also be caused by or occur during maintenance operations. Transient pollutants have received little attention to date because they are difficult to sample and analyze. However, it is important to characterize and quantify transient pollutants so that practical control measures may be developed. (44,89)

TABLE 4-19
QUANTITIES OF PAH IN A COAL-DERIVED LIQUEFACTION PRODUCT

PAH	Quantity (ppm)
Naphthalene	347
2-Methylnaphthalene	1325
1-Methylnaphthalene	383
Biphenyl	89
2,6-Dimethylnaphthalene	328
1,3-Dimethylnaphthalene	181
1,5- and/or 2,3-Dimethylnaphthalene	202
Benzo[*a*]pyrene	41
Benzo[*a*]anthracene	18
Phenanthrene	413
Acenaphthalene	20
Acenaphthene	61
Fluorene	205
1-Methylfluorene	152
2-Methylfluorene	245
1-Methylphenanthrene	107
9-Methylanthracene	42
Chrysene	98
2-Methylchrysene	102
6-Methylchrysene	64
3-Methylchrysene	106

(SOURCE: 69, p. 670)

TABLE 4-20
PAH COMPOUNDS IN SYNTHOIL

Compound	Result (ppm)
Phenanthrene	413
Benzo[*a*]anthracene	18
Benzo[*a*]pyrene	41

(SOURCE: 109, p. 22)

TABLE 4-21
PAH IN COED SAMPLES

	Results (ppm)		
Sample type	BaP	BaA	Phenol
Product separator liquor	8.0		
Drier liquor	9.3		
Syncrude	51	Trace	Trace
Unfiltered raw oil	107	42	270
Filtered raw oil	96	52	400

(SOURCE: 109, p. 32)

TABLE 4-22
ORGANIC SULFUR COMPOUNDS IN THE PRODUCTS OF COAL HYDROGENERATION

	Indiana No. 5 coal		Kentucky coal	
Product	Molecular formula	Identification[a]	Molecular formula	Identification[a]
Light oil	C_8H_6S	Benzothiophene	C_5H_6S	Methylthiophene
	C_9H_8S	Methylbenzothiophene	$C_6H_{10}S$	Diallylsulfide
	$C_{10}H_{10}S$	Dimethylbenzothiophene		
Heavy oil	C_5H_6S	Methylthiophene	$C_{14}H_8S$	Benzo[*def*]dibenzothiophene
	$C_8H_{10}S$	Tetrahydrobenzothiophene	$C_{16}H_{10}S$	Naphthobenzothiophene
	$C_{11}H_{10}S$	Benzylthiophene	$C_{17}H_{12}S$	Methylnaphthobenzothiophene
	$C_{12}H_8S$	Dibenzothiophene	$C_{20}H_{12}S$	Dinaphthothiophene
	$C_{13}H_{10}S$	Methyldibenzothiophene	$C_{21}H_{14}S$	Methyldinaphthothiophene
	$C_{14}H_8S$	Benzo[*def*]dibenzothiophene		
	$C_{16}H_{10}S$	Naphthobenzothiophene		
	$C_{17}H_{12}S$	Methylnaphthobenzothiophene		
	$C_{20}H_{12}S$	Dinaphthothiophene		
Asphaltenes	Spectrum not well resolved		$C_{16}H_{10}S$	Naphthobenzothiophene
			$C_{20}H_{12}S$	Dinaphthothiophene

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[a] Based upon molecular formula determined by high-resolution mass spectrometry; other isomeric forms are possible in some instances.

(SOURCE: 15, p. 2-62)

Possible sources of transient pollutants are presented in Table 4-23.

TABLE 4-23

POSSIBLE SOURCES OF TRANSIENT POLLUTANTS

Coal handling - broken belt, spills

coal grinder - breakdown or motor failure

coal screening - breakage, dust

Coal dryer - fire or broken bag filters

Coal pretreater (if used) - fines carryover, tar emulsion

Lock hoppers - valve failure, dust in vent gas, plugging

Coal pressurizer (slurry feeder) - breakdown or leaks

Slurry preparation - flashing of vapor if coal becomes wet

Ash removal - dust, steam cloud, odors, if valves fail

Tar handling - emulsions, solids, paste

Dust scrubber - plugging, spills of sour water

Shifting - plugging and cleanup, dust

Acid gas removal - chemical purge, sulfur or entrainment in CO_2 vented due to upset

Methanation - leaks of toxic CO, carbonyls, nickel dust

Sulfur plant - odors, fire, chemical wastes, burner failure

Hydrogen manufacture - similar to a complete gasification plant

Steam supply - failure, contamination with solids or gases

Power supply - failure

Motors, turbine drives, gear reduction, noise due to equipment malfunction

Pumps and seals - breakdown, leaks

Compressors and seals - breakdown, leaks

Valves, piping, flanges - leaks

Heat exchangers - leaks, rupture

Furnaces - flameout, smoke, or noise due to malfunction, tube rupture

Water treating - odors, oil, suspended solids, etc., from sudden surges upstream

Ponds - leaks, overflow

Solids disposal - dust, leaching, runoff due to erosion

Instrumentation - false readings, failure

TABLE 4-23 (Continued)

Blowdown system - overloading, freeze up
Pressure relief valves - leaks
Vacuum exhaust - on steam condensers, distillation, dust cleanup
Blind changing - leaks, spills
Sampling - purges, leaks, upsets
Product storage - vapor breathing, spills, tank cleaning
Other - corrosion, erosion, drains on equipment

(SOURCE: 89, p. 140)

5.0 STRAWMAN PROBLEMS

The purpose of this section is to provide a "strawman" set of potential problems for each of the five panels of the workshop. A significant activity for each panel at the workshop will be the identification and prioritization of potential health and environmental problems, for the entire energy cycle of each technology. The "strawman" problems presented here are to be considered only a starting point and are offered to panelists for augmentation and modification.

5.1 Examples of Health Effects Associated with Coal Conversion

5.1.1 Introduction

A careful assessment of potential health and environmental impacts of coal conversion is required so that protection is adequate for the industrial workers, the population in the vicinity and the population at large. To do this, the potential for adverse health effects must be assessed at each stage of the fuel cycle for each process.

Much research has already been done on the health effects associated with coal extraction. The occurrence of chronic respiratory and metabolic disease among miners is well documented. Less well known are the effects of airborne dust and fines resulting from coal preparation and storage.

Eastern soft coal is high in sulfur and during conversion, sulfur dioxide, nitrogen oxides,* carbon monoxide, hydrogen sulfide, hydrocarbons, particulates and other airborne pollutants are emitted. These pollutants may then undergo atmospheric reactions to form additional hazardous agents. Due to exposure to these pollutants, acute respiratory illness and chronic lung or skin disease may result in the exposed human population. Even when control technology is in position to control final emissions, fugitive emissions associated with the various processes may adversely affect the work force.

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*It has been estimated that in gasification processes 90 percent of the organic sulfur will be converted to H_2S and 78 percent of the nitrogen to ammonia.

The heating of coal during conversion may additionally cause the vaporization and release of certain trace elements such as arsenic, beryllium, cadmium, lead, nickel, selenium, silica and vanadium. Some of these will also be present in the particulate dust created during conversion. Arsenic, beryllium, cadmium and nickel are known carcinogens affecting the lungs and some of the others may also lead to chronic illness as a result of long-term exposure.

Polycyclic aromatic hydrocarbons represent some of the most potentially harmful emissions during conversion. During coking at temperatures between 778°F - 958°F byproducts of coal conversion, some of which are known carcinogens (for example, benzo(a)pyrene, chrysene, dibenzo(a,h) anthracene, dibenzo(a,g) fluorene, -naphthylamine and benzidine) are released. It has been shown that the coal tars produced at high coking temperatures, consisting of both polynuclear aromatics and azo compounds were far more carcinogenic than those produced at lower temperatures. Both gasification and liquefaction processes involve sufficient heating of the coal to release the polynuclear aromatics and azo compounds. The exact identity of the hydrocarbons produced is a function both of the coal resource and the process.

Our knowledge of the health effects of such pollutants is in general very limited and needs to be greatly improved. Moreover, there is a very real possibility that there will be both synergistic and antagonistic effects of materials in the complex organic mixture produced during the conversion processes and combustion.

Occupational safety and risks involved in mining are of great concern and are well documented for coal mining processes. The workers who are associated with the coal processing plants are also at high safety risks, from mining and extraction of the resources to the utilization of the products by the end user. A comprehensive analysis of the various non-nuclear energy systems concludes that a significantly greater number of deaths and injuries are associated with the coal energy system per unit of delivered energy than with the crude oil and/or natural gas systems.

In order to define the health problems of coal conversion one must first have source characterization information identifying the contents of the various process streams, emissions and wastes requiring disposal for each different process. This permits the researchers to determine the biological activity and potential health effects associated with the various pollutants. As the levels of the pollutants in the streams, not just their identity, become known they should be incorporated into dose-response studies with animal models. As plants reach the demonstration phase, it is also desirable to sample the actual process streams and to submit these to screening the higher level testing to determine what synergistic reactions are present.

Only when exposure data and health effect data are both available can an assessment of the impact of that subtechnology or technology be made. Exposure data must take into account the source characterization data, the plant and employee monitoring data, and the results of transport models for both steady state operations with control technology in place and accidental situations. The health data required include both animal test results and occupational and general health epidemiology data.

Based on existing knowledge it is possible to make a few general comments concerning emissions from processes associated with a generalized conversion technology. For example, simple hydrocarbons such as benzene, toluene and olefins may be produced in reactor off-gas and separation operations associated with coal conversion. Similarly, phenols, heterocyclic compounds and alcohols may be released from the reactor, fractionation and hydrocracking operations; and aquatic emissions from hi-Btu gasification can be expected to contain phenols, cyanide, ammonia, sulfides, oil and various suspended solids.

Included in the following text is an overview of what is known about the nature of coal conversion pollutants. Most of the pollutants are common to other fossil fuel technologies as well as across the coal gasification and liquefaction subtechnologies. What will vary are their concentrations and perhaps the structure of some of the complex hydrocarbons.

5.1.2 Emissions

Various organic, inorganic, particulate and gaseous materials are released during coal conversion. Many of these compounds are present in the ambient environment and generally physical, chemical and biological mechanisms are available for their detoxification. During coal conversion, however, the increased concentrations of these various pollutants may result in increased health impacts, especially among the worker population. The potential pollutants may be divided into various subgroups such as gases and aerosols; particulates, hydrocarbons; trace elements; and tar, char and fly ash.

- Gases and Aerosols
  - Oxides of Sulfur-SO_x may be adsorbed on the surface of particulates and easily carried to the lung. This combination of SO_x plus particulates has been shown to affect persons with a tendency to bronchial problems. The amount of SO_x released (and therefore the potential for adverse health effects) is a function of the coal resource (eastern coal is higher in sulfur than western coal), the conversion process, the control technology and the presence of particulate matter.
  - Oxides of Nitrogen-NO_x undergoes reactions with particulates and hydrocarbons resulting in the production of photochemical oxidants which are eye irritants. They may also adversely affect persons with cardiopulmonary problems. Ingestion of nitrates can result in formation of nitroamines, known carcinogens and mutagens. Because they are so reactive nitrate production should be voided.
  - O_3, CO, CO_2, H_2, CH_4, NH_3, Water Vapor-these pollutants are associated to some extent with the vapor

phase releases from all of the coal conversion processes and with the combustion of the resulting synthetic fuels. Their impacts range from short-term adverse effects to increased incidence of respiratory diseases in workers and the general public. Most often they act as cofactors with other pollutants.

- Particulates-coal dust and coal fines are associated primarily with the mining and coal preparation operations. Particulates are, however, associated with all phases of the conversion process. The particles 0.5 to 5.0 in diameter are retained in the lungs following respiration and represent the major size hazard. Hydrocarbons and trace elements are easily adsorbed onto the surface of the particles which become the vehicle for entry of these deleterious substances into the body. Particulates also cause pneumonconiosis (black lung disease) in miners after chronic occupational exposure.

- Hydrocarbons-The exact identity of the species is process specific. Screening tests are needed to determine the biologically active components of effluent streams from all coal conversion processes. The products may be similar to those from coal combustion, coking, petroleum refining or coal pyrolysis, but unique combinations may enhance the effects. Enzyme induction of the hydrogenases responsible for PAH metabolism may prove a specific test for activity of these compounds but more work is needed to verify the connection. Results of screening tests on various fractions from various processes which have been performed in different laboratories should be incorporated.

  - Aromatic hydrocarbons-these are found in gas streams during the coal gasification process in the coking temperature range of 100°C-200°C. Benzene is a known carcinogen and xylene, toluene vapors act as mucous membrane irritants.

  - Aromatic Amines-aniline, pyridine, and quinolines are nitrogen containing compounds. Chronic exposure will result in liver, kidney, central nervous system damage. Aniline is known to be weakly carcinogenic, readily absorbed through skin.

  - Phenols-these are oxygen-containing compounds released at temperature range of 150°-200°C. Phenols are not found at higher temperatures. They act as co-carcinogens and promote the carcinogenic activity of various PAH's. They are also mutagenic. Chronic exposure damages the liver, kidney, pancreas and spleen even in the presence of detoxification enzymes in liver. Acute exposures cause burns. Phenols are readily absorbed through skin.

- Polynuclear aromatic hydrocarbons (PAH"s) - Benzo(a) pyrene, anthracene, chrysene, dimethylbenzanthracene, and methylcholanthrene are some of the known carcinogens formed during combustion and gasification of coal, at the coking temperatures of 340°C - 490°C. In the atmosphere, PAH's are associated with soot particles and particulates. When absorbed on particulates, PAH's are easily transported inside body via the nasal passage. See Table I for a list of carcinogentic activity of PAHs. PAHs have been implicated in development of lung and skin cancer on the basis of epidemiological as well as laboratory studies. Other cancer sites observed in the animal laboratory studies include the urinary organs, larynx, sinus, pancreas, blood forming organs, stomach and digestive tract.

- PAHs enter the body by inhalation, skin contact or ingestion. Ingested PAHs are generally excreted intact. Ingestion is generally only associated with the occupational population.

- PAHs are metabolized to epoxides, dihydrodiols, phenols, and quenones and only exert their effects after metabolism. Often the metabolite is far more active than the parent compound (e.g., a diolepoide has been shown to be the active metabolite of B(a)P). The metabolites will bind to DNA, RNA, and protein. More work is needed to determine other active metabolites of PAHs.

- SO_2, NO_2, ozone and aliphatic hydrocarbons with PAHs in separate studies have been shown to enhance the development of lung squamous cell carcinoma. On the other hand, Vitamin A and certain antioxidants with PAHs have been shown to exert a protective effect against development of cancer. Many more data are needed to define these synergistic effects.

- PAHs do across the placental barrier and DMBA and 3-methylcholanthrene are teratogenic.

5.1.3 Epidemiology

The problem with most of the health effects of coal conversion products is that there is a long latent period before they are manifest. Some epidemiological studies of coke oven workers, gas (coal) workers and coal carbonization workers have shown increased incidences of lung, skin and bladder cancer among the worker populations. These processes emit similar process streams and the effects of coal gasification/liquefaction might be expected to be similar.

- Increased SO_x concentrations associated with particulates was shown to result in respiratory effects in the general population in several community-wide studies. However, the effects of ozone NO_x phenols, etc. have not been as well documented. Nor have the effects of trace elements been investigated.

- Prospective and retrospective studies should be implemented for coal conversion workers to attempt to quantify these epidemiological issues.

- General population studies should also be designed for localities downwind of coal conversion facilities to determine whether the coal conversion effects are similar to those from coking, etc., and an attempt should be made at quantification.

- Trace Elements-carcinogenicity of trace elements depends on route of entry and retention time in the various tissues. Naturally occurring trace elements in coal include arsenic, cadmium, beryllium, chromium, iron, lead, mercury, nickel, selenium, fluorine and vanadium.

    - Arsenic is a known carcinogen and teratogen as well as having toxic effects.

    - Cadmium inhalation results in gastro-intestinal discomfort and respiratory difficulty. Cadmium is also a carcinogen and bioaccumulates in the liver and kidneys.

    - Beryllium inhalation may lead to lung fibrotic condition; it is also carcinogenic.

    - Chromate salts are essential in low doses, but greater amounts cause a variety of toxic effects including skin and lung cancer.

- Lead is known to interfere in enzymatic functions and induces circulatory and central nervous system disorders.

- Acute exposure to mercury results in pulmonary and mental degradation.

- Iron particulate inhalation results in chronic "bronchitis" or red lung disease. Ferrous oxide (FeO) may transport benzo(a)pyrene into the lungs as FeO can penetrate walls of the lung, bronchi and alveoli without damaging mucous or ciliary barrier.

- Nickel is a known carcinogen and has been shown to cause lung cancer.

- Long term exposure to selenium may result in liver and kidney disease, however, problems are expected only in areas with high natural selenium levels.

- Fluorine, while beneficial in limited amounts, may cause severe effects if taken in excess.

- Vanadium's long range effects include cardiovascular disease, kidney damage and pulmonary fibrosis. Vanadium acts synergistically with oxides of sulfur.

o Tar, Char and Fly Ash-these byproducts are produced at high temperatures during combustion and coal gasification. They may cause disease of skin, genito-urinary and nervous systems, liver and kidney. Tars have been shown to cause skin cancer in painting experiments with laboratory animals.

5.1.4 Areas Where Research is Needed

o Epidemiology studies are needed to determine the effects of coal conversion pollutants on the general population taking into account such additional variables as smoking, age, sex, etc.

o Data from registries of cancer and cardiac diseases need to be compared for areas near coal conversion facilities and areas far removed.

o Monitoring data should be correlated with epidemiological data to see if any unsuspected pollutant effects can be elucidated.

- Animal toxicological studies are needed to determine the target organs for the coal conversion pollutants taking into account the likely routes of entry.

- Gas-aerosol mixtures should be tested on both animals and humans to determine their effects on respiratory function. The aerosols should contain both trace elements and hydrocarbons.

- Pollutant streams or various fractions should be submitted to a battery of *in vitro* carcinogenicity and mutagenicity screening tests. A desirable battery should be designated and the testing performed under uniform conditions including a plate test, and tests for DNA repair, chromosome breakage and cell transformation.

- The synergistic relationship of chemicals and trace elements remain to be determined with regard to cell-proliferation, immunological changes, tissue repair and tumor development especially in the respiratory system.

- Source characterization results should be extended to derive exposure estimates for the various occupational groups and the general population by process.

- The effects of NO_x emissions on the human body should be studied to determine the nature of the respiratory effects. The synergistic effects of NO_x and various hydrocarbon fractions need to be determined.

- The possibility that SO_x is a co-carcinogen needs to be investigated.

- The activated forms of the PAHs need to be determined along with the target organs for their effects.

- Effects of Ozone + PAHs need to be investigated.

- Effects of aliphatic hydrocarbons and PAHs need to be investigated.

- The role of particulates and various other coal conversion emissions on the development of respiratory disease should be determined.

- Various PAHs should be tested in animal systems to determine if they are teratogenic.

- The mechanism by which Vitamin A exerts a protective effect when administered with PAHs relative to the development of cancer should be determined.
- An epidemiological study of coal conversion workers should be carried out including both industrial hygiene and personal habits data.
- The firing of one region of an in situ gasification plant may result in unusual hazards for miners underground preparing other shafts.
- The high temperatures and pressures of coal conversion facilities may present a unique danger from explosion.
- Methods for removal of tars and PAHs from workers' skins need to be evaluated and new methods may be needed.
- The possibility that enzyme induction of hydrogenases responsible for PAH metabolism can serve as a measurement of the biological effects of PAHs should be investigated.
- Means should be sought to minimize the high noise levels associated with coal preparation.
- The safety of workers should be studied due to the potential for explosion during the hydrogenation phase.
- The hazards associated with various processes approaching commercialization should be quantified and compared.
- The degree to which phenols intensify the effects of PAHs and trace elements should be determined.

5.1.5 Safety and Occupation Risks

Occupational risks in coal conversion energy systems are associated mainly with accidents. These occupational hazards could be the result of human error, structural or mechanical failures, sabotage or natural phenomena such as earthquakes. These accidents may occur at any step of the coal conversion system from mining through transportation and extraction to the utilization of the gas or liquid products.

- Mining Accidents-these are common to all coal technologies, but unique mining problems may be associated with in situ gasification.
    - Accidents due to mine roof and rib fall, and mine leakage are associated with the underground and deep mining.
    - Gas or dust explosions, explosions in the electrical system, or fires can be accounted for human error or structural or mechanical malfunctions.
    - The effects of firing up one region of an in situ gasification plant while men are underground nearby are unknown.
- Coal Conversion-there is an increased potential for explosion of volatile and combustible substances due to the high-operating temperatures of up to 300°C and pressure of 3000 lbs per square inch.
    - Coal conversion workers face problems of removing PAH's and tars from their skin.
- Storage, Pipeline and Truck Distribution-accidents of this nature are due to material handling, pipeline corrosion and leaks and transportation methods.
- The possibility of fugitive or accidental releases of toxic sulfur-containing releases such as H_2S, CS_2, or COS from which eastern coal should be investigated.

5.2 Characterization Measurement and Monitoring

5.2.1 Introduction

The Characterization, Measurement and Monitoring (CMM) program supports all the subsequent activities which lead to the health and environmental assessment of the energy systems. For this reason the success and validity of the final assessments rest heavily on the status of the CMM program. This program should include development of suitable methodologies, instrumentation and systems for improved measurement capability, comprehensive monitoring, generation of reliable information for occupational exposure, and information necessary for the evaluation of pollution control and abatement technology.

The CMM effort should be conducted from the start of any energy technology operation and continued through the reclamation of exposed areas. It should include both operational and applied research activities. The operational activities should include characterization of specific processes and monitoring studies at specific sites, whereas applied research activities should lead to the advancement of measurement technology.

Source term characterization has been discussed in Section 3; in what follows we identify some of the potential problems which should be addressed by the CMM program in support of coal conversion technology.

- Monitoring instrumentations for criteria pollutants do not have the appropriate sensitivity for baseline measurements and for evaluation of photochemical smog formation-relevant components of fuel cycle are baseline monitoring, conversion and utilization.

- The drift rate and temperature sensitivity of most automated instruments for criteria pollutants are inappropriate - relevant components of fuel cycle are baseline monitoring, conversion and utilization.

- There is an urgent need for improvement in the calibration system and the long-term stability of calibration standards--relevant fuel cycles are baseline monitoring, conversion and utilization.

- Identification and quantification of trace organics is an extremely complicated problem because of the diversity of these compounds and the complexity of the coal related matrices, and environmental samples.

    - Improved detection systems are needed for baseline monitoring, conversion and utilization.

    - Many trace organics occur in low concentrations beyond the sensitivity of present techniques.

    - Thus, long sampling periods followed by sample preparation is necessary; techniques for collection and preservation of trace organics need improvements.

  - Rapid-feedback field measurement techniques are needed to identify and quantify trace organics.

- The mobility, bioavailability and toxicity of trace metals depend on the particular chemical form in which they occur. There is a need for development of trace element speciation.

  - Many trace metals are most hazardous in their lowest oxidation states, the form in which they may be emitted from coal conversion facilities.

  - Analysis of trace metals generally is not done under field conditions or on continuous basis, since present techniques require sample concentration procedures.

  - Because of the instability due to the reducing environment of coal conversion processes, a real time field analysis system is needed to adequately determine the trace metal species and their transformation byproducts.

- Automated particulate analyzers which can measure short-term particulate averages are needed.

- There is a real need for air monitoring rationale, for coal conversion facilities, i.e., how many stations at what sites, for what season, etc. It is presently difficult to compare results from various networks because of uncertainties resulting from the network designs.

- There is considerable potential (specifically for in-situ processes) for contamination of ground water, and monitoring needs are greatest in this area.

- Leaching of trace elements or trace organics from solid waste is a potential source of groundwater and surface water pollution and must be monitored.

- There is a need for better understanding of groundwater movement, in order to design a meaningful monitoring strategy for groundwater pollution detection.

- Methods for automatic cleaning and calibration of water monitors need improvement.

- A water monitoring program which is designed based on the reactivity of different pollutants is needed.

- There is a real need for further development of instruments to make remote measurements of air and water quality. Remote sensing devices could help to rapidly establish baseline data for regions that are otherwise inaccessible.

In addition to these an occupational monitoring program containing the following elements should be developed.

- Selection of a specific high exposure group of workers for continuous detailed testing.

- Broad based screening program for respiratory effects, specifically in relation to particulates.

- Characterization of deposition of organics on skin of workers and development of methods for their removal.

- Development of trace element dosimeters for determination of individual worker's exposure. Of specific interest are PAH, and trace metals.

5.3 Aquatic Concerns

5.3.1 Introduction

A major environmental concern associated with coal conversion technologies is the potential for degradation of both surface and groundwater. The extent of this degradation will be, in part, site specific (depending upon ambient water quality and the waste water treatment technology employed to remove contaminants). Additionally, certain generalities which, though resulting from contaminants released at a specific site in a particular place, are more generic in their application. These include determination of transfer and transport coefficients which will enable predicting source terms and critical pathways of effluent components in and through the aquatic environment. The following is a partial listing of potential problems which may be associated with the various coal conversion technologies.

In Situ Gasification

- Groundwater migrating through combustion zones may become contaminated by leaching of trace elements and inorganic salts from coal ash and by leaching of organic contaminants (e.g., phenols, pyridines, anilines, quinolines, aromatic hydrocarbons) from coal tars. Additionally, over time, there may be leaching of relatively insoluble components from the coal ash and tar.

- Subsidence may disrupt groundwater flow patterns and rates or may result in interconnection of aquifers.
- Disposal of water pumped from the coal seam during dewatering operations may lead to contamination of surface waters.
- Groundwater may be contaminated by escaping gases in the event of gas leakage.
- In situ processing may result in thermal pollution of groundwater which may result in more complete leaching of salts, heavy metals and other substances contained in the coal.

5.3.2 Gasification and Liquefaction

- Waste water effluents may contain suspended particulates, ammonia, phenolics, hydrogen sulfide, and potentially toxic trace metals. Additionally, aromatic hydrocarbons, and substituted sulfur and nitrogen heterocyclics may be present. The levels of these materials that will be released to surface waters will be dependent upon the adequacy of removal during the treatment process, the levels produced during the specific conversion process, and through potential accidental spills or leaks from waste water streams.
- Leachates from solid waste disposal sites may result in contamination of ground and/or surface water. The quality of the aqueous leachate will depend upon the type of conversion facility, the type of coal utilized, methods of disposal, and specific characteristics of the aquatic and soil components characteristic of the specific site used for waste disposal.
- Rain falling on coal storage piles will result in runoff which may lead to contamination of ground and/or surface waters. The types of contaminations will be dependent on the specific coal used, the age of the coal pile, and the coal pile configuration used. The level of contamination will depend upon the size of the coal pile, the proximity of the coal pile to ground and/or surface waters, and engineering methodology used to contain any runoff or leached materials.

For gaseous pollutants changes from the typical approach to air quality dispersion will occur either at the earth's surface or at the top of the mixing layer. Many widely used models assume complete reflection at both surfaces. Thus there is no mechanism for possible transport or diffusion of gases upward through the top of the mixing layer. This is not strictly correct since penetration of this layer can always occur to some extent, at least by molecular diffusion.

The situation is potentially more important at the ground surface since the various gaseous pollutants are known to interact upon surface contact. This interaction may take the form of adsorbtion, absorption or chemical reaction with soils, water, plants or inorganic materials. Some work has been done in this area but the effect of each significant individual gaseous pollutant from coal conversion must be analyzed to determine how surface interaction alters traditional transport and diffusion values.

In the case of particulates and liquid aerosols the principal effort should concentrate on the nongaseous behavior of these pollutants. The entire physical spectrum of such pollutants must be determined for each coal conversion process in order to identify the significant differences between these emissions and those from similar industries such as conventional coal extraction and combustion, petroleum refining or oil shale operations.

For each particulate or liquid aerosol identified as significant data must be developed on:

- Gravitational deposition rates for both settling and suspended particulates and liquids
- Chemical and physical processes occurring at underlying interfaces
- Possible re-entrainment from underlying surfaces.
- Non-isokinetic behavior of specific particulates or liquids.

- The ultimate fate of contaminant components in the aquatic environment must be determined to enable evaluation of critical pathways to man of these components as well as the specific doses that might be delivered through the different pathways.

Other potential water quality problems which may result from any of the coal conversion technologies include the following:

- Deposition from air emissions may be washed into surface water bodies by rain.
- Construction of the coal conversion facility may result in soil erosion with an increased sediment load ultimately reaching surface waters.
- Thermal and chemical pollution of surface waters may occur from the wastewaters of cooling systems.

Another concern, especially in western regions, is the high consumptive use of water by the coal conversion facility. Even the use of a wastewater treatment scheme which involves recycling/reuse of process wastewaters will result in water consumption. The following is a partial listing of potential problems or areas where more research concerning water availability and use is needed.

- The availability of water at proposed coal conversion sites needs to be determined.
- Regional studies need to be conducted to determine water use and availability and the effects of water consumption by coal conversion processes on downstream uses.
- Downstream changes in water quality resulting from water withdrawal by coal conversion facilities need to be determined. For example, increases in the salinity of downstream water may present a problem, especially in western coal regions.

These potential alterations in water quality may result in adverse effects on the aquatic habitat and biota. Characterization (ecological and chemical) of the contaminants expected to be released from the various coal conversion processes is necessary. The magnitude of potential aquatic ecosystem effects will depend on the fate and transformation of the contaminants which reach surface waters. Other potential problems and areas requiring more research are identified below:

- Preoperational baseline monitoring of the aquatic ecosystem is needed.
- Methods used to detect changes in habitat and also changes in the structure and function of aquatic communities need to be evaluated.
- The intake of water for coal conversion may result in adverse effects on ichthyoplankton populations due to entrainment/impingement.
- The potential toxic, mutagenic and carcinogenic effects of released contaminants (e.g., trace elements) on indigenous aquatic biota need to be determined.
- Evaluation of the potential for bioaccumulation of released contaminants in aquatic organisms is needed. For example, trace metals may be accumulated by mollusks and other bottom feeders.
- Food web relationships should be evaluated to determine the potential for biomagnification of toxic substances.
- The potential for concentration of toxic contaminants in bottom sediments and the resulting effects on benthic organisms should be evaluated.
- The additive, synergistic and antagonistic effects of released contaminants on aquatic biota need investigation.

5.4 The Effect of Coal Conversion on Air Quality

5.4.1 Introduction

The development, construction and operation of coal conversion facilities will have an impact on both the air quality and local meteorology in any area where such facilities are located. Many of the effects resulting from these operations will be quite similar to those resulting from any industrial operation of the same size. This is particularly true if these facilities are compared with other energy oriented operations such as petroleum refineries or metallurgical coke ovens. The primary emphasis in study of coal conversion processes should be placed on identification of those factors affecting air quality which are unique to either coal conversion in general or to one of the specific processes utilized in coal conversion.

Atmospheric effects resulting from any industrial activity can be divided into four general categories:

- Changes in air quality due to transport and diffusion of pollutants.
- Chemical and physical transformation of pollutants in the atmosphere.
- Local changes in meteorology and climatology and the resulting effects of these changes.
- Site specific effects.

For each coal conversion process each of these categories must be examined to identify those specific features of the process which will have an impact.

5.4.2 Transport and Diffusion

At the present time changes in air quality due to transport and diffusion of pollutants are considered to be independent of the nature of the industrial source and nearly independent of the nature of the emissions. This includes gases, particulates and liquid aerosols.

However, since each individual industrial process has its own unique set of emissions, air quality is affected in slightly varying ways. These differences will also occur from the various coal conversion processes. The principal task is to determine which, if any, of these variations are significant enough to warrant individual study apart from generalized air quality dispersion modeling.

At the present time sufficient data is not available to identify those pollutants from coal conversion which are significantly unique in their transport and diffusion behavior to warrant separate study. Such data must be developed before any individual studies of specific processes are undertaken.

5.4.3 Chemical and Physical Transformation

Many pollutants including gases, particulates and liquid aerosols are known to be transformed either chemically, physically or both as the material is dispersed through the atmosphere. As is the case with transport and diffusion, the chemical and physical changes are independent of the type of source for the material. However, in this instance there is a much greater likelihood that synergistic effects may result in significantly different air quality for different initial combinations of pollutants. This indicates the importance of knowing the specific emissions for each coal conversion process and the chemical and physical transformations which will result.

In general five major pollutant changes can be identified:

- Sulfur oxides
- Nitrogen oxides
- Hydrocarbons and other organics
- Particulates and liquid aerosols
- Trace metals.

There is considerable overlap in these chains and an almost infinite number of ways for synergistic effects. The particulate and aerosol chain, for example, is quite likely to involve sulfates, nitrates, nongaseous hydrocarbons and organics, and trace metal chlorides, sulfates and nitrates. There are direct links between nitrogen oxides and reactive hydrocarbons and organics in oxidant chemistry, and between sulfur and hydrocarbons in the organic sulfur compounds such as methyl sulfide. Each of these pollutant chains must be investigated to determine if any significant differences exist between the chemical and physical transformations associated with various coal conversion processes and those associated with other known processes such as fossil-fuel combustion or petroleum refining.

The basic problem may take one of two forms:

- For pollutants unique to coal conversion, studies are required to determine the chemical, photochemical and physical transformations occurring in a typical polluted atmosphere.
- For pollutants not unique to coal conversion, studies are required to determine if the particular circumstances associated with coal conversion produce any significant changes in the chemical, photochemical or physical transformations.

5.4.4 Local Atmospheric Transformations

Local atmospheric transformations caused by coal conversion can have both primary and secondary effects on air quality and meteorology. In the primary sense these facilities may directly alter the local meterology. In the secondary sense this altered local meteorology may result in changes in transport, diffusion and transformation of pollutants.

Atmospheric emissions of gases, particles, liquids and waste heat will cause changes such as:

- Changes in quantity, quality and frequency of occurrence of precipitation, dew and fog.
- Changes in cloud microphysics and dynamics, resulting in changes in the local intensity, frequency and duration of storms.
- Modifications of solar and terrestrial radiation fluxes.
- Changes in atmospheric thermal structure, thermal winds, and the capabilities of the atmosphere to disperse pollutants.
- Modifications to concentrations of mesoscale vorticity.
- Degradation of visibility.
- Increases in the acidity of precipitation.

The above changes may result from releases of gaseous pollutants, particles, liquid aerosols, liquid water, water vapor and/or waste heat.

In a secondary way many of the above meteorological changes can affect the chemical and physical transformation rates for the various pollutants. For many pollutants, these rates are known to vary as a function of temperature, relative humidity and solar radiation.

Also in a secondary way changes in meteorological patterns will result in changes in transport and diffusion of pollutants. Transport and diffusion rates will be particularly affected by changes in the thermal stability which may drastically alter turbulent diffusion parameters.

However, for both the primary and secondary effects the principal task lies in the identification of the differences between the changes resulting from the operation of coal conversion facilities and those resulting from any other similar operation.

5.4.5 Site Specific Features

Although it is not within the scope of the present effort to address individual air quality problems which are specific to each site where coal conversion facilities might be located, there is significant merit to be gained in identifying the types of site specific problems which may occur. Such problems may be either precisely site specific or in a more general way result from the particular region of the country where facilities are located.

The most typical site specific effect is that of the local topography. Nonlevel terrain will affect both the transport and diffusion of pollutants and the possible changes in local meterology. The intensity of these changes will be a function of the nonuniformity of local conditions. This nonuniformity may be the result of:

- Natural land formations, such as mountains and valleys.

- Interfaces between land surface and large water bodies.

- Anthropogenic interferences due to the presence of the coal conversions structure itself, other surrounding structures, or even nearby towns or cities.

- Combinations of all of the above.

These site specific effects cause such widespread variation that it is impractical to attempt to address them in a general study of coal conversion.

Another class of local influences which may occur arises due to the regional variations in climatology. In different areas of the U.S. there are differences in the predominant air masses and solar radiation. Since the rate of reaction of many atmospheric chemical changes is strongly influenced by temperature, relative humidity and/or the intensity of solar radiation, it is important to know what the significant differences are in the chemical cycles of coal conversion air pollutants under these varying conditions. Any major effects identified should be incorporated into generalized planning for location of coal conversion facilities.

5.4.6 Conclusions

The major problem in assessing the potential effect of coal conversion facilities on air quality is to determine if air quality is affected differently by such facilities as compared to other similar industrial operations. If there is no difference then determination of air quality effects can be made by merely applying existing techniques to the emissions data for each coal conversion process. If significant differences are identified, programs should be undertaken to determine the effects of these differences. At the present time it is not obvious that any such differences exist.

5.5 Terrestrial Concerns

5.5.1 Introduction

Major land disturbances have been caused by the extraction of coal resources by both surface and subsurface mining. The following is a partial listing of potential problems which may occur as a result of development of coal conversion technologies.

- Surface mining will destroy existing vegetation and habitats and will result in reshaping of the terrain.
- Land subsidence may occur as a result of in situ gasification and underground mining.
- Land use overlying in situ gasification sites may be restricted.
- Reclamation of strip-mined lands may be difficult in western regions due to the arid climate.
- Surface gasification and liquefaction facilities may require additional land for the disposal of solid wastes.
- The construction and location of pipelines will result in additional land use and loss of vegetation.

All of the problems identified above will result in physical alterations of the terrestrial environment. It is anticipated that these land disturbances will have an adverse effect on local wildlife populations. Wildlife will be forced to relocate due to the loss of habitat and due to the increased noise and human disturbance associated with the development of coal conversion facilities. This may result in crowding, greater competition and disruption of mating habits and predator-prey relationships at the relocation site. Other potential problems and areas requiring research involving wildlife are identified below.

- The initial stages of revegetation efforts may not provide suitable habitat for wildlife.
- Site specific preoperational monitoring of wildlife populations is needed to quantify potential changes in species diversity and population size.

- Aqueous effluents from coal conversion processes need characterization. Adverse effects on wildlife might be realized directly through the use of contaminated waters for drinking purposes and indirectly through ingestion of aquatic organisms (e.g., fish).
- Food web studies should be conducted to determine the potential for bioaccumulation of specified contaminants at lower trophic levels. Effects on wildlife need to be assessed.
- Toxicity studies should be conducted to determine the effects on wildlife of potentially hazardous contaminants which may be released to the atmosphere.

Effects of atmospheric emissions on terrestrial biota are also a matter of concern. Various pollutants (e.g., hydrocarbons, CO, PAH, SO_x, NO_x, O_z, and particulates) may be emitted during coal gasification and liquefaction processes.

The industry must plant to maintain emissions within the levels for presently mandated pollutants and to determine what materials might need regulation under the terms for new source performance standards, under Federal, state and local regulations.

The atmospheric chemistry of emissions such as hydrocarbons, PAH's, phenols, amines, NO_x, etc. is not well understood. Under the influence of oxygen, sunlight or other environmental factors, certain of these compounds may undergo transformation to potentially noxious substances. The industry must control transformable materials at levels which will meet existing or anticipated regulations.

Another area of major concern involves the disposal of solid wastes generated by the coal conversion facility. Surface disposal of refuse from coal cleaning; ashes, slags and chars from the conversion processes; and sludges from water treatment processes may have adverse effects on vegetation. Potential problems and research areas are identified below:

- There may be difficulty with revegetation of solid waste disposal sites.
- Substances contained in the disposed materials may have toxic effects on vegetation as well as herbivores and carnivores via accumulation, biomagnification or habitat alteration.
- Studies should be conducted to determine uptake and accumulation of toxic materials by biota on disposal sites; transport and effects through food webs need to be explored.

Coal liquefaction solid wastes and residues, for example, will be produced at 200 pounds per ton feed coal or greater levels. These wastes contain silicates and trace elements and in some cases, hydrocarbons and PAHs. These wastes must be disposed of by the industry in a way considered environmentally acceptable under existing Federal, state and local regulations.

For coal conversion processes that are net consumers of water, the industry must determine the impact of their water usage in the region of the siting.

Crude and oil products have been shown to have a wide range of environmental and biological effects. Their transport and handling are regulated at the present time under the Federal, state and local laws. The coal liquefaction industry must be in compliance with these existing laws and should anticipate future regulations for those materials which may be unique to the coal liquefaction process.

The siting of coal liquefaction industries in undeveloped areas will produce a wide range of socioeconomic effects. The industry must anticipate economic and sociologic impact on surrounding regions.

The introduction of coal liquefaction fuels and products will have impact on cost and consumption of fuels derived from other sources. To insure the orderly introduction of synfuels into the market place this impact must be evaluated.

In order to determine the overall benefit of coal liquefaction technology, it is necessary to perform an integrated assessment incorporating biomedical, socioeconomic and environmental factors.

Other potential problems and areas requiring more research are identified below.

- Characterization of specific contaminants emitted to the atmosphere from the coal conversion industry is needed.
- The transformation of emitted contaminants to more toxic compounds needs investigation. For example, photochemical reactions of nitric oxide and nitrogen dioxide with unsaturated hydrocarbons can produce peroxyacetyl nitrate (PAN) which is extremely phytotoxic (ORNL 1977).
- The fate of released contaminants must be determined. Factors such as mobility, transport, bioaccumulation, retention and degradation need to be considered.

Pollutants dispersed to surrounding ecosystems have a potential for damage beyond short term, direct effects, thus, the industry must evaluate the fate and effects of such pollutants as appropriate during the course of its development and assess these effects as required by existing and anticipated regulations.

The pathways of pollutant dispersal within ecosystems are not well defined. Models should be developed for these pathways as needed to assure compliance with existing Federal, state and local regulations.

- Preoperational characterization of ecosystems existing at the proposed site is needed.
- The chronic and acute effects of actual contaminants reaching representative, important plant and animal species should be determined.

- The additive, synergistic and antagonistic effects of emitted contaminants on plants and animals need evaluation. For example, toxic responses in plants occur in shorter time periods when ozone is mixed with low levels of sulfur dioxide (Britt and Hushon, 1976).
- Potential for transfer to man.

APPENDIX A

TECHNOLOGY PROCESS STEPS AND ASSOCIATED WASTE STREAMS AND POTENTIAL CONSTITUENTS

Coal storage
Coal crushing, washing and grinding
Coal drying
Partial oxidation
Briquetting
Coal gasification
Gas quench and scrub
Acid gas removal and sulfur recovery
Water gas shift
Methanation
Wastewater treatment
Air pollution control
Solid waste control
Utility power production
Cooling towers
Auxiliary processes
Slurry preparation
Pyrolysis/hydrocarbonization
Hydrogenation
Hydrotreating
Phase separation
Fractionation
Pregasification
Gasification (in situ)
Surface processing (in situ)
Support systems (in situ)

COAL STORAGE

Process Information

Coal storage is necessary and desirable for both production and use. Most coal conversion plant designs allow for an approximate 30-day stored supply. For designs using low-Btu content coals, the amount of stored coal will be larger than for plants using higher-Btu content coal feeds. A typical size for a storage pile for a 250 scfd plant may be 15 acres at 25 feet high. (106)

Waste Streams and Potential Constituents (44)

Liquid

- o Rain runoff and leachate
  - acids, organics, sulfur, soluble metals and suspended solids (see Table A-1).

Air

- o Oxidation and spontaneous combustion
  - smoke, fumes, volatile compounds
- o Windblown particulates
  - coal dust

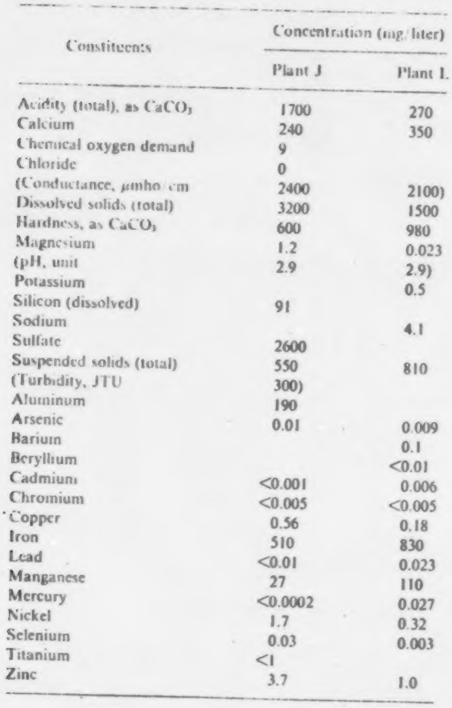
Remarks:

The variability of coal makes prediction of behavior of coal piles difficult.

Currently very little is known about the effect of residence time, weather, pile size and coal composition of the leachate from coal storage piles. Data are becoming available. (51)

TABLE A-1

CHARACTERISTICS OF COAL PILE DRAINAGE



Constiteents	Concentration (mg/liter)	
	Plant J	Plant L.
Acidity (total), as $CaCO_3$	1700	270
Calcium	240	350
Chemical oxygen demand	9	
Chloride	0	
(Conductance, μmho/cm	2400	2100)
Dissolved solids (total)	3200	1500
Hardness, as $CaCO_3$	600	980
Magnesium	1.2	0.023
(pH, unit	2.9	2.9)
Potassium		0.5
Silicon (dissolved)	91	
Sodium		4.1
Sulfate	2600	
Suspended solids (total)	550	810
(Turbidity, JTU	300)	
Aluminum	190	
Arsenic	0.01	0.009
Barium		0.1
Beryllium		<0.01
Cadmium	<0.001	0.006
Chromium	<0.005	<0.005
Copper	0.56	0.18
Iron	510	830
Lead	<0.01	0.023
Manganese	27	110
Mercury	<0.0002	0.027
Nickel	1.7	0.32
Selenium	0.03	0.003
Titanium	<1	
Zinc	3.7	1.0

(SOURCE: 22, p. 34)

COAL CRUSHING, WASHING, AND GRINDING

Process Information

Primary breakers are used for initial size reduction, secondary and final crushers reduce the coal to the required size. Up to 20 percent of the run-of-mines coal may consist of rock, debris, and gangue, and is rejected, most of it at the primary breaker. This represents a significant solid waste stream since coal conversion plants may use 25,000 tons of coal per day.

Coal washing to remove refuse may produce 12 to 25 pounds of solid waste per 100 pounds of clean coal. Ideally, the washing system should be designed for complete recycle of the wash water so that a wastewater effluent does not result (106).

Grinding is the final stage of size reduction and is designed to produce coal of the appropriate size for the conversion process.

Waste Streams and Potential Constituents (44)

Liquid

- o Waste water
  - Suspended solids and leachate from coal

Air

- o Coal dust

Solids

- o Rock, debris, gangue, coal
- o Solid wastes from coal washing

Remarks:

Controls exist for all potential effluents. Solid wastes may present disposal problems due to the large quantity generated.

COAL DRYING

Process Information

Coal drying may be a necessary step in the coal conversion process. thermal drying of coal is accomplished by contacting the coal with hot combustion gases at temperatures aroud 755°K (900°F). (112).

Waste Streams and Potential Constituents

Air

- Off gases from the dryer
  - coal dust
  - combustion gases (CO_2, SO_2, NO_x)
  - volatile organics

Remarks:

Particulates are usually controlled by cyclones or baghouses. Scrubbers may be needed to control SO_x. Regulation of combustion parameters is used to control NO_x. (112)

Volatile organics are known to be potentially toxic, however, there are few data concerning these components. Effluents have not been fully characterized, but may be more hazardous than gasifier effluents. The dryer and its off gases may contain aromatic hydrocarbon vapors, and the dried coal may contain condensed heavy tars. It is possible that these tars contain compounds with boiling points in excess of the dryer temperature. These compounds may melt at the dryer temperature and exert sufficient vapor pressure to be exhausted from the dryer with the product gas; or they may form by polymerization reactions of the off-gas components. (51).

PARTIAL OXIDATION

Process Information

Partial oxidation may be necessary to reduce the coal caking tendencies. Partial oxidation is carried out in thermal dryers and may be accomplished simultaneously with coal drying.

Waste Streams and Potential Constituents

See "Coal Drying"

Remarks:

See "Coal Drying"

BRIQUETTING

Process Information

Coal fines rejected from curshing and sizing operation or collected from fugitive dusts may have to be compacted into briquettes which are of suitable size for use as fuel or feed to a gasifier, e.g., fixed bed gasifiers. To produce briquettes coal fines are compacted by mated rollers. An asphalt or tar binder, and baking may also be used. (112)

Waste Streams and Potential Constituents

Air

- Coal dust
- Vent gases if baking is involved
  - volatile coal components

Remarks:

The coal dust is collected in conventional control equipment and is recycled to the briquetting operation, or used as fuel. Hydrocarbon control may be required if the briquettes are baked and volatile, potentially toxic hydrocarbons are emitted in sufficient amounts. These can be controlled by afterburners or an adsorption process. Fugitive emissions may present control problems.

COAL GASIFICATION

Process Information

Gasification is the key process step in coal gasification, and may also be an integral part of a coal liquefaction operation. Gasifier systems include: coal feeding devices, ash removal devices, and the gasifier.

The function of the coal gasification operation is to produce raw low/medium Btu gas by reacting coal with a steam/air or steam/oxygen mixture.

Many types of gasifiers have been developed to produce gas from coal; each has characteristics that make it unique, both from a process and an environmental viewpoint. These differences must be taken into account in the environmental assessment of coal gasification technology.

The production rates and compositions of coal gasifier output streams are affected by:

- o Mechanical features of the gasifier
  - bed type; fixed, fluidized, entrained
  - gasifier geometry
  - gasification media: reactants, and reactant ratios
  - mode of reactant introduction
  - ash removal: mode, location, ash condition
  - energy input: autothermic, electrothermic, solids circulation
- o Gasifier operating conditions
  - temperature
  - pressure: atmospheric or pressurized
  - residence time
- o Coal feedstock properties
  - ash content
  - ratio of volatile matter to fixed carbon content
  - nitrogen content
  - sulfur content
  - minor and trace constituents

Differences or changes in these parameters can affect the raw gas and ash compositions. These in turn are directly related to the environmental impact of a gasifier, since the discharge streams from coal feeding and ash removal devices may contain ash and raw gas components. The composition of the raw gas can also affect the requirements for downstream gas purification and pollution control processes. (112)

Waste Streams and Potential Constituents

Air

- o Coal feeder vent gases
  - trace elements
  - tars
  - phenols
  - organics
  - nitrogen compounds, e.g., ammonia, nitrogen cyanide
  - coal particulates
  - sulfur compounds, e.g., H_2S, COS, organic sulfides, mercaptans, disulfides, thiophenes
  - hydrogen cyanide
  - oil aerosols
  - substituted ring compounds containing sulfur and nitrogen (in gasifiers that tend to produce heavy oils and tars)
- o Start-up vent stream
  (similar to coal feeder vent gas)
- o Raw product gas
  (similar to coal feeder vent gas)
- o Fugitive emissions
  (similar to coal feeder vent gas)

Liquid (57)

- o Blowdown water and condensate from ash quench
  - soluble ash components
  - impurities in make-up water
  - tars
  - carbonyl sulfide
  - organics
  - ammonia
  - condensable hydrocarbons
  - trace elements.

Solid

- o Wet or dry ash or ash slurry
  - organics
  - mineral matter
  - unreacted carbon
  - trace elements

- Slag
  - 5 to 55% carbon
  - minerals in coal
  - raw gas components
- Char

Remarks:

The gasifier components do not normally contain a major emission source; vent gases, start-up vent streams and raw product gas should be controllable. However, fugitive emissions may present an environmental hazard.

The effect of the reactor temperature gradient on condensation of components products is unknown, as is the effect of shut-down on the deposition of carcinogenic products on surfaces that may be contacted by maintenance and/or production workers.

The presence of trace elements in the ash or in the product gas depends upon their presence in the coal. Estimates of trace element disposition in a 10,000 ton/day gasifier are presented in Table A-2.

Current data indicate that some of these species may be partially volatilized or gasified under the conditions present in coal gasification. Some of the species will tend to exist as oxides; and, still other species would be expected to be present in the elemental form. In general, the expected trace element species in the off-gas have low vapor pressures and are not expected to survive the purification processes that will be employed in most gasification facilities (57).

The principal waste from a gasifier vent is solid ash, char or slag. The solid waste is usually slurried with water which becomes contaminated with solids and leachates from the ash. A partial list of major components in ash slurry water is presented in Table A-3. (51, 106)

However, because of the large surface areas common to most ashs and chars, they may adsorb oil or tar when they are dumped into or slurried with water that contains dissolved or suspended oil or tar.

TABLE A-2

DISPOSITION OF TRACE ELEMENTS

Constituent	Mean concentration in coal (ppm)	Feed rate[a]		In exit gas		In gasifier ash	
		lb/day	kg/day	lb/day	kg/day	lb/day	kg/day
As	14	280	127	182	82	98	45
B	100	2,000	910	200	90	1,800	820
Be	1.6	32	15	6	3	26	12
Cd	2.5	50	23	31	14	19	9
Cr	14	280	130	Neg.		280	130
F	61	1,220	553	122	55	1,098	498
Hg	0.20	4	2	4	2	Neg.	
Mo	7.5	150	68	15	7	135	61
Ni	21	420	190	101	45	319	145
Pb	35	700	317	441	200	259	117
Sc	2.1	42	19	31	14	11	5
V	33	660	300	198	90	462	210
Zn	270	5,400	2,450	540	245	4,860	2,205
(Cl	0.14%)	28,000	12,700	<25,200	<11,430	2,800	1,270
(Ti	0.07%)	14,000	6,350	1,400	635	12,600	5,715
Sb	1.3	26	12	9	4	17	8
Co	9.6	192	87	Neg.		192	87

[a] Feed rate based on 10,000 tons/day (9000 metric tons/day) of clean coal (after removal of rock, debris, and gangue).

(SOURCE: 105)

TABLE A-3

EXAMPLE OF WATER ANALYSIS FROM GASIFIED ASH SLURRY TANK

Component	Amount (μg liter)
(pH	8.8)
CaO	101
MgO	161
Na	17.5
K	8.5
Zn	0.03
Fe	0.22
NH_4	157
NO_2	0.13
NO_3	3.32
PO_4 (total)	0.81
Cl	85
SO_4	216
CN	0.52
H_2S	9
$KMnO_4$ (consumed)	18
Chemical oxygen demand	16.0
SiO_2	4612
Suspended solids	3918

(SOURCE: 106, p.4b.2.1-9)

They may also concentrate the dissolved trace elements from the recycle water. Then, although the trace elements in the char or ash itself may be inert, adsorbed trace elements could be removed by leaching.

Ash disposal options include return to the coal mine, pond retention or use as landfill. Ash treatment or disposal site construction must be employed to minimize leachate contamination of groundwater systems. Char may be used as a fuel in the utility boiler. (106)

- sulfur species
- organics
- trace elements

Remarks:

The solids and liquids from primary treatment processes are burned, recycled or processed. Residuals from further processing are sent to controlled final disposal sites. (112)

GAS QUENCH AND SCRUB

Process Information

The purpose of the gas purification operation is to remove undesirable constituents such as particulates, tars, oils and acid gases, which could foul the processing elements downstream, and to cool the gas sufficiently for further processing.

The choice of gas quenching and scrubbing equipment depends in part upon the types of impurities present in the gas, the pressure of the system, and whether or not sulfur removal is required.

The particulate removal steps commonly consists of cyclones, electrostatic precipitators, and water or oil scrubbers to remove coal dust, ash and tar aerosols entrained in the raw product gas leaving the gasifier. The solids may constitute as much as 1-5 wt percent on even 10 wt. percent of the raw coal fed to the gasifier.

In the gas quenching and cooling step, tars and oils are condensed and particulates and other impurities such as ammonia are scrubbed from the raw product gas. Quenching involves the direct contact of the hot gas with an aqueous or an organic quench liquor. The composition and quantity of liquid wastes depend upon gasifier process considerations, the nature of the quenching medium and the temperature to which the gas is cooled.

Waste Streams and Potential Constituents

Liquid (106)

- o Spent quench liquor
  - suspended and dissolved tars
  - oils
  - coal fines
  - ash
  - dissolved gases
  - raw gas bubbles containing H_2S, CO, NH_3, and HCN.
  - phenols

Solids (20)

- o collected particulate matter from dry removal systems
  - coal fines
  - ash

ACID GAS REMOVAL AND SULFUR RECOVERY

Process Information

The sulfurous compounds to be removed during acid gas treatment are generated during coal gasification. The primary sulfur compound is hydrogen sulfide (H_2S). However, carbonyl sulfide (COS), carbon disulfide, mercaptans and carbon dioxide may also have to be removed.

Acid gas treatment is a multistep process that concentrates the acid gas stream in order to remove CO_2 and H_2S either together (non-selective acid gas removal) or separately (selective acid gas removal). Acid gas treatment to remove sulfur is sometimes used in low-Btu gasification processes to allow compliance with sulfur emission limitations applicable to low-Btu gas combustors and in high-Btu gasification systems to remove sulfur compounds to protect the methanation catalyst. CO_2 is removed to meet product quality specifications and for economic reasons. Waste gases from the acid gas removal unit go to the sulfur recovery unit, the type of which is determined by the method (selective or non-selective) of removal. Removal of sulfur compounds consists usually of ultimate conversion of these compounds to elemental sulfur which is sold or disposed of. (106).

Waste Streams and Potential Constituents

Air (20, 112)

- Tail gases from the sulfur recovery plant
  - sulfur compounds, e.g., COS, CS_2, H_2S
  - hydrocarbons including solvent vapors
  - carbon dioxide
  - ammonia
  - hydrogen cyanide

Solids (20)

- Spent sorbents and reactants
  - cyanide
  - heavy metals
  - organics
- Filter cake of micron-sized sulfur particles

Liquid (112)

- Liquid effluents from solvent blowdown
  - solvents
  - solvent degradation products
  - hydrocarbons from gas stream
  - trace elements from gas stream

Remarks:

Sulfur removal units, themselves, must have tail gas treatment units to reduce sulfur emissions. Unrecovered sulfur in Claus plant tail gas includes primarily H_2S, elemental sulfur, SO_2, and lesser amounts of other sulfur compounds. Additionally, most units using Claus technology are not capable of recovering sulfur from COS, or CO_2, or sulfur-containing organics such as CH_3SH and C_2H_5SH, leaving these gases to be vented to the environment. (106)

An additional environmental problem may be caused by the light hydrocarbons that are present in the process gas. The physical characteristics of ethane and propane are similar to carbon dioxide and acid gas treatment processes may discharge these species with the carbon dioxide effluent.

Tail gas cleanup processes may produce a froth which, when filtered, results in a wet or dry filter cake of micron-size particles. Disposal of these surfur particles may pose environmental hazards. (106)

WATER-GAS SHIFT

Process Information

In the downstream methanation reaction, hydrogen is reacted with residual carbon monoxide to form methane:

$$3H_2 + CO \rightarrow CH_4 + H_2O$$

Therefore, the ratio of hydrogen to carbon monoxide in the gas feed to the methanation reactor should be approximately 3:1. This ratio is generally less than 3:1 in most gasifier types; therefore, some of the carbon monoxide is catalytically reacted with steam in a water-gas shift reaction:

$$CO + H_2O \rightarrow H_2 + CO_2$$

Two general types of catalysts are available for this reaction. Cobaltmolybdenum catalysts are not poisoned by sulfur and may be employed before sulfur removal. Older catalyst types are poisoned by sulfur and must be used after the sulfur removal stage of the process.

Waste Streams and Potential Constituents

None Identified.

Remarks:

No outstanding problems are foreseen for the shift conversion operation. It is possible that some catalyst breakage may occur, which could result in catalyst dusts being carried down stream. However, in normal operation or for normal maintenance functions, no extraordinary hazards are foreseen other than the presence of high concentrations of carbon monoxide in the vessels. (51)

The primary effect of the shift catalyst will be its ability to operate on species other than carbon monoxide. For example, there is contradictory evidence that sulfur-tolerant shift catalysts may be active in the hydrogenation of carbonyl sulfide:

$$COS + H_2 \rightarrow CO + H_2S$$

This point could be important, environmentally, because the fate of carbonyl sulfide in the sulfur removal and recovery sections of the process is not well defined. (57)

METHANATION

Process Information

The sweetened, coal-derived synthesis gas contains a large quantity of carbon monoxide (low-Btu value) and hydrogen (low-Btu/unit volume). In order for this gas to be brought up to pipeline quality, the carbon monoxide and the hydrogen contents must be reduced to low enough values to yield a product with a heating value greater than 900 Btu/cf. (89)

To accomplish this objective all existing processes use the methanation reaction, which occurs in the presence of a catalyst, and combines carbon monoxide and hydrogen to produce methane and water:

$$CO + 3H_2 \xrightarrow[\text{800° to 900°F}]{\text{high pressure}} CH_4 + H_2O$$

Waste Streams and Potential Constituents

None Identified.

WASTEWATER TREATMENT

Process Information

The type and quantity of contaminants found in wastewaters are functions of the chemical characteristics of the initial feedstock to the process, the type and severity of conditions in the conversion units, and the type of subsidiary treatment upstream of the water-wash, quench, or cooling-condensation steps.

The major contaminants in primary coal gasification streams are: tars, oils, BTX, fly ash, sulfur compounds, ammonia, hydrogen cyanide, thiocyanate, phenols. (64)

Cleanup of wastewater streams is a complex multistep process directed at removing contaminants group by group, each of which requires a different methodology. Conversion wastewater can be treated by many of the same techniques used to treat industrial wastewater, including:

- oil/water separation
- flocculation/flotation
- dissolved organics removal
- liquid extraction
- biological oxidation
- carbon adsorption
- cooling tower oxidation
- acid gas and ammonia stripping
- forced evaporation
- evaporation ponds (112)

The wastewater treatment plant will be a major facility in a conversion plant. The design goal for water use in commercial-scale coal conversion plants will probably be zero discharge. Thus, the philosophy in designing treating facilities for liquid wastes is to purify liquid streams only to the extent necessary for reuse in specific areas of the plant. Less than 5% of all water in most commercial-plant designs leaves as an aqueous discharge and this water leaves in ash slurries, treatment sludges, and aqueous by-product ammonia. (20)

Waste Streams and Potential Constituents (20)

Air

- o Vent gases (oil/water separation; flocculation; forced evaporation)
    - sulfur species
    - cyanides
    - hydrocarbons
    - trace elements
- o Regeneration gases (carbon adsorption)
    - organics
    - inorganics
- o Emissions from cooling tower oxidation
    - partially oxidized organics
    - cyanides
    - sulfur species
    - trace elements
- o Stripped gases (acid gas and ammonia stripping)
    - hydrogen cyanide, carbonyl sulfide, carbon desulfide
    - mercaptans, thiophenes
    - ammonia
    - trace elements
    - cyanides
- o Gaseous emissions from evaporation ponds
    - volatile organics
    - sulfur species

Liquid

- o Byproduct tar and oil (oil/water separation)
- o Byproduct phenols (liquid extraction)
    - organics
    - trace elements
- o Cooling tower blowdown
    - organics
    - trace elements

Solids

- Sludges and semi-solids
  - inorganics
  - organics
  - cyanides
  - trace elements
  - chlorides
  - fluorides
  - ammonia

Remarks:

Spent wastewater sludge, about which little is known, may resemble that from municipal or industrial wastewater treatment, and will require disposal as a solid waste. The most important constituents of this sludge are trace elements, which may accumulate as indicated in Table A-4. Leaching of potentially hazardous trace elements into surface waters or groundwaters constitutes a potentially serious environmental hazard. (64)

TABLE A-4

ESTIMATE OF TRACE ELEMENT EFFLUENTS FROM WASTEWATER TREATMENT FACILITY (WWT)

Constituent	Quantity entering WWT		Best removal efficiency (%)	Emission rate[a] in final liquid effluent		Rate of accumulation in WWT sludge	
	lb/day	kg/day		lb/day	kg/day	lb/day	kg/day
As	182	83	97.1	5	2	177	80
B	200	90	Unknown	Unknown		Unknown	
Be	6	3	99.5	Neg.		6	3
Cd	31	14	99.6	Neg.		31	14
Cr	Neg.		99.3	Neg.		Neg.	
F	122	55	Unknown	Unknown		Unknown	
Hg	4	2	98.3	Neg.		4	2
Mo	15	7	80	3	1	12	5
Ni	101	45	99.5	1	0.5	100	45
Pb	441	200	99.4	3	1	438	199
Se	31	14	95	2	1	29	13
V	198	89	97.8	4	2	194	87
Zn	540	245	94	32	15	508	230
Cl	25,200	11,430	Unknown	Unknown		Unknown	
Ti	1,400	635	98.5	21	10	1379	626
Sb	9	4	72	3	1	6	3
Co	Neg.		95	Neg.		Neg.	

[a] Based on 10,000 tons/day (9000 metric tons/day) of clean coal feed having a trace element composition equal to the average of 101 U.S. coals and the use of removal processes demonstrating the highest removal efficiency for each element.

(SOURCE: 106, p. 46.2.1-13)

AIR POLLUTION CONTROL

Process Information

The modules required in the air pollution control operation depend on the composition of the gaseous effluents generated in the other operations. Typically, one or more of the following modules will be used:

- particulate control
- sulfur control and recovery
- nitrogen oxides control
- hydrocarbon control

These control modules may, in turn, produce liquid, solid or gaseous effluents. The liquid and solid streams frequently will require further treatment; gaseous streams may be released to the atmosphere or processed in another air pollution control module. Liquid effluents may contain spent sorbents, scrubbing liquors, or sour condensate. Solid wastes include coal fines, ash, sulfur, spent sorbents, and catalysts. (106)

Waste Streams and Potential Constituents (20)

Air

- Treated gases
  - sulfur species
  - nitrogen oxides
  - trace elements
  - hydrocarbons

Liquid

- Spent sorbents and reactants (sulfur recovery blowdown)
  - organics
  - heavy metals
  - cyanides
  - other hazardous species
- Liquid streams from regenerating activated carbon or polymers
  - suspended and dissolved organics
  - suspended and dissolved inorganics

Solid

- Particulates from particulate removal
  - coal dust
- Byproduct sulfur
  - trace elements
- Spent sorbents and catalysts (hydrocarbon removal)
  - organic species
  - heavy metals
  - other hazardous species

Remarks:

Many data are available on the treated gases from processes used to control sulfur and hydrocarbon emissions in other industries, e.g., petroleum, petrochemical, natural gas, etc. These data should be applicable to low-Btu gasification systems.

Liquid and solid waste streams may present more of an environmental hazard. Little characterization data is available. Characterization is necessary to determine treatment and disposal requirements. (21)

SOLID WASTE CONTROL

Process Information

The solid waste control operation may contain any or all the following modules to treat the solid effluents generated by the plant:

- o sludge reduction (incineration and pyrolysis)
- o chemical fixation
- o landfill
- o land farm

The choices of specific processes will depend upon the waste streams generated, and the location of the plant.

Waste Streams and Potential Constituents (21)

Air

- o Gaseous emissions from sludge reduction
  - volatile organics
  - chlorides
  - fluorides
  - sulfur species
  - nitrogen oxides

Solids

- o Reduced sludge
  - organics
  - cyanides
  - trace elements
  - other hazardous pollutants
- o Fixed solids from chemical fixation

Remarks:

Gaseous wastes must be characterized to determine the need for further treatment.

Characterization data on both reduced sludge and fixed solids are necessary to determine stability, leachability and pollution potential. Data on treatment of coke oven effluents may be applicable to reduced sludge. Data on fixed solid wastes have been reported for other industries (petroleum, petrochemical, nonferrous metals); applicability of these data is uncertain. Solid wastes from chemical fixation and sludge reduction will probably be disposed of in a landfill. (20)

UTILITY POWER PRODUCTION

Process Information

In general, a large utility power plant will be used to generate process steam and electric power. Fuels ranging from cleaned coal to product may be used.

Waste Streams and Potential Constituents

Similar to conventional power plant, e.g., SO_x, NO_x, particulates, fly ash, bottom ash and slag. Sources and types of residuals will depend upon fuel.

Remarks:

Emissions will be held to new source performance standards and will lead to a need for solid waste disposal. (106)

COOLING TOWERS

Process Information

Wet cooling towers may be used to reduce the temperature of water used in process cooling. Treated process wastewater may be used for process cooling water makeup. This water may have trace quantities of contaminants remaining after treatment in addition to chemicals added to inhibit corrosion and biological growth. The contaminants may be stripped as air contacts water in the tower.

Waste Streams and Potential Constituents

Air

- Gaseous emissions and entrained droplets
  - zinc
  - chlorine
  - sulfuric acid
  - phosphates
  - phenols
  - copper complexes
  - ammonia
  - carbon monoxide
  - cyanide
  - thiocyanates
  - trace elements

Remarks:

Pollutants should be similar to cooling tower pollutants in other industries; trace contaminants in recycled process water used as cooling water makeup may possibly present some unique problems.

Modern cooling towers have extremely low drift which reduces the environmental hazard. However, even pure water vapor leaving the tower may create serious nuisance problems, e.g., icing or fogging. (106)

AUXILIARY PROCESSES

Process Information

Auxiliary processes might include air compression, oxygen and hydrogen generation, and compressed or liquid gas storage, e.g., carbon dioxide, oxygen or nitrogen.

Waste Streams and Potential Constituents

Air

- combustion products
- hydrocarbon vapors
- sulfur and nitrogen oxides
- particulates

Liquid

- oils
- spent chemicals
- solvents
- suspended solids

Solid

- ash and fines
- sludge
- mineral waste (106)

Remarks:

Environmental problems should be the same as in similar existing facilities.

SLURRY PREPARATION

Process Information

Slurry preparation consists of mixing the crushed/pulverized coal with a liquid, generally a solvent. All hydrogenation processes which use a solvent will use slurry preparation and preheating. (44)

Waste Streams and Potential Constituents

Air

- Stack gas stream
  - hydrocarbons
  - solvent vapor
- Vent gases
  - hydrocarbon
  - solvent vapors

Remarks:

PYROLYSIS/HYDROCARBONIZATION

Process Information

High temperature gases are used to strip volatiles from coal and/or to chemically add hydrogen to coal in this module. Pyrolysis requires introduction of steam and oxygen to react with the coal while hydrocarbonization uses heated hydrogen.

Vapor leaving the pyrolysis or hydrocarbonization reactor is cooled by quenching with either water or oil. Non-condensibles are used elsewhere in the process. A separation step may be included. (44)

Waste Streams and Potential Constituents

Air

- o Preheater flue gas
    - Carbon monoxide
    - Nitrogen oxides
    - Hydrogen sulfide
    - Ammonia
    - Hydrocarbons

Solids

- o Particulate coal
- o Ash/slag mineral matter
- o Char

Remarks:

HYDROGENATION

Process Information

In this step hydrogen is used to convert portions of the coal to soluble compounds which dissolved, leaving an insoluble carbon residue and mineral matter in suspension.

Variations include catalytic, non-catalytic, and donor solvent systems. These operations are usually carried out at high pressure (44).

Waste Streams and Potential Constituents

Air

- Preheater flue gas
  - Carbon monoxide
  - Nitrogen oxide
  - Hydrogen sulfide
  - Ammonia
  - Hydrocarbons

Solid

- Spent catalyst (intermittent)

Remarks:

HYDROTREATING

Process Information

Coal-derived liquid products are treated with hydrogen to remove sulfur, nitrogen and oxygen compounds by converting them to hydrogen sulfide, ammonia and water. Hydrotreating also hydrogenates unsaturated materials.

Hydrotreating is a high pressure and high temperature process. The reactor product is depressurized and cooled. An oil and an aqueous phase are formed. The oil is stripped to remove hydrogen sulfide and ammonia. (44)

Waste Streams and Potential Constituents

Air

- o Preheater flue gas
  - carbon monoxide
  - nitrogen oxides
  - ammonia
  - hydrocarbons
  - hydrogen sulfide
- o Catalyst removal and replacement
  - particulates
  - hydrocarbons
  - ammonia
  - hydrogen sulfide

Water

- o Condensate from overhead vapors
  - phenols
  - ammonia
  - sulfide

Solid

- o Spent catalyst (intermittent; in gas or liquid stream)

Remarks:

PHASE SEPARATION

Process Information

Solids, liquids and gases are separated in numerous different unit operations. In coal liquefaction processes, situations arise involving two, three, and four phases. The phase separations are gas/solid, gas/liquid, liquid/solid, liquid/liquid, gas/liquid/solid, and gas/liquid/liquid/solid.

Operations include cycloning, filtering, centrifuging, decanting, settling, and depressurizing.

Waste Streams and Potential Constituents

Air

- Flash drum vapors
  - hydrocarbons
  - sulfides
  - SO_2
  - NH_3
  - particulates

Liquid

- Condensate from overhead condensor
  - oils
  - light hydrocarbons
  - phenols
  - ammonia
  - dissolved sulfides

Solid

- Particulate coal
- Ash or slag
- Tars and heavy residuals
- Char

Remarks:

FRACTIONATION

Process Information

The fractionation module separates crude feedstock into product and by-product components.

Primary operations used may be distillation, vacuum flashing, and stripping. In addition, heat must be supplied, depressurization may be necessary, and cooling is required.

Waste Streams and Potential Constituents

Air

- Uncondensed gases from condenser
  - hydrogen sulfide
  - carbon dioxide

Liquid

- Condensate from overhead vapors
  - light hydrocarbons
  - dissolved salts

Solid (don or solvent processes only)

- Particulate coal
- Ash/slag
- Char

Remarks:

PREGASIFICATION

Process Information

Pregasification is preparation of the coal seam for subsequent gasification, and generally consists of increasing seam permeability. Although some coal seams are naturally quite permeable and do not require pregasification, the majority of seams do. Methods of increasing bed permeability include electrolinking; pneumatic linking; fracturing by hydraulic pressure, explosives, deviated drilling and reverse combustion. (100)

Waste Streams and Potential Constituents

Air

Water

- Water from dewatering
  - natural groundwater contaminants

Remarks:

GASIFICATION (in situ)

Process Information

The methods of gasification can be classified as shaft type, shaftless type, or a combination of both. Shaft-type gasification requires the drilling of underground channels or passageways. Shaftless gasification requires only surface drilling operations. Current research is almost entirely devoted to the development of shaftless technology.

Gasification involves introduction of gasifying agents, i.e., oxygen, stream and carbon dioxide, and subsequent reaction with the coal seam to produce carbon monoxide, carbon dioxide and hydrocarbons. The product gases are removed via production wells. (100)

Waste Stream and Potential Constituents

Air

- Product gas leaks
  - carbon monoxide
  - carbon dioxide
  - hydrogen
  - water vapor
  - nitrogen
  - methane
  - volatile organics
  - heavier entrained hydrocarbons
  - hydrogen sulfide
  - trace elements

Water

- Groundwater/surface water contamination by combustion residues
  - phenols
  - pyridines
  - anilines
  - quinolines
  - aromatic hydrocarbons
  - trace elements
- Water from dewatering
  - groundwater contaminants
  - contaminants from combustion residues

Remarks:

Due to hydraulic gradients, migration of groundwater will occur through coal seams and burned-out areas which lie below the water table. This may cause soluble components in or sorbed on the ash or char to be leached out and transported away from the gasification site. An increase in dissolved organic material could result from partial dissolution of coal tars formed during gasification. Phenols, pyridines, anilines, quinolines, and aromatic hydrocarbons pose varying hazards.

Incorporation of inorganic salts and trace elements into the groundwater could occur via leaching of ash components. The dispersion of soluble contaminants will be a function of groundwater flow and the sorptive properties of the materials through which the leachate passes (100)

SURFACE PROCESSING (in situ)

(Similar to conventional gasification processes. See "Gas Purification", "Sulfur Removal and Recovery", "Shifting", and "Methanation".)

APPENDIX B

PROCESS DESCRIPTIONS AND DIAGRAMS FOR SELECTED TECHNOLOGY PROCESSES

LIQUEFACTION

- H-Coal
- Solvent Refined Coal (SRC)
- Exxon Donor Solvent (EDS)
- Entrained Pyrolysis

GASIFICATION

- BIGAS
- HYGAS
- Synthane
- Fixed bed, stirred (MERC)
- Fixed bed, slagging (GFERC)
- Fluidized-bed, two-stage pressurized
- Fluidized-bed, three-stage

IN-SITU GASIFICATION

- Linked vertical wells (LVW)
- Packed-bed
- Longwall generator (LG)
- Steeply dipping bed (SDB)

H-COAL PROCESS DESCRIPTION

The H-COAL process is a catalytic liquefaction process that converts coal under conditions of high pressure and temperature to liquid hydrocarbon products. The process can utilize the bituminous coals of the eastern United States, or lignite or subbituminous coals of the western United States.

In the H-COAL process, dried pulverized coal is reacted with hydrogen under conditions of high temperature and pressure producing liquid hydrocarbon products. These crude hydrocarbon products can be further refined by conventional processes into gasoline and low sulfur fuel oil. In this process, coal is crushed to 40-200 mesh via a primary and a secondary crusher, dried and mixed with hydrogen, preheated and fed to the hydrogenation reactor in which a catalyst bed is kept ebullient by internally recycled oil. The coal reacts with hydrogen at 3000 psig pressure and 850°F to form (principally) hydrocarbon products.

The products of the reactor consist of a vapor stream and a liquid stream. The vapor stream is cooled and scrubbed to yield light fractions, a hydrogen-rich recycle gas, and a low sulfur fuel gas. Sour water and acid gas from these operations are treated to recover ammonia and sulfur. The liquid stream comprised of liquid, ash, and untreated coal is flashed, first at high pressure and then at low pressure to separate light hydrocarbons which are subsequently recycled. The bottom liquid from the flash operation is concentrated and filtered to remove ash and other solid products. This liquid stream is mixed, preheated and fractionated. The overhead product of fractionation, essentially naphtha, is cooled, stabilized and stored. The middle fraction, containing light oils is cooled and stored. The fuel oil, bottom product of the column, is recycled to the coal slurry tank.

Process requirements for oxygen are produced in a conventional air separation plant and hydrogen is produced in a Texaco partial oxidation process.

The sulfur plant takes the H_2S-rich streams from gas processing, hydrogen plant, and sour water stripping and produces elemental sulfur in a conventional Claus plant. Tail gas from the Claus plant is processed in a tail gas treating unit before release to the atmosphere. Storm water collected from areas of the plant where contamination will occur flows to a holding basin. Contaminated water from the storm basin is treated for oil removal and is then filtered in a deep bed filtration unit. Other waste water streams are treated in a Chevron unit where NH_3, CO_2, and H_2S are separated from liquid waste streams. Effluent water from the Chevron waste water treatment unit may contain traces of hydrocarbons. These hydrocarbons are separated in this unit and the effluent water is delivered to a phenol recovery unit where phenol removal to about 4 ppm is expected. Treated water from the phenol recovery unit is used as a make up to the cooling water system where residual phenols would be oxidized. (5)

Developer. Hydrocarbon Research Inc., Trenton, N.J.

Status. The H-Coal process was developed by Hydrocarbon Research, Inc. (HRI), as a further application of the ebullated-bed processing technology fractions (H-oil process). Early development of the H-Coal process involved research with a bench-scale unit and a PDU and preparation of a conceptual process design. Independent evaluations in 1963 and in 1976 confirmed the technical and economic feasibility of the H-Coal process.

Based on experimental operations of bench-scale and a 2.5-tons/day PDU for synthetic crude oil and boiler fuel production, the preliminary design for construction of a 600-tons/day pilot plant has been completed. A detailed design of the pilot plant was completed by December 1977.

The pilot plant site has been selected (Catlettsburg, Kentucky) by Fossil Energy, at the recommendation of HRI, from sites offered by the private partners. Environmental assessment has been completed and shows that the plant will not significantly affect the environment of the proposed site.

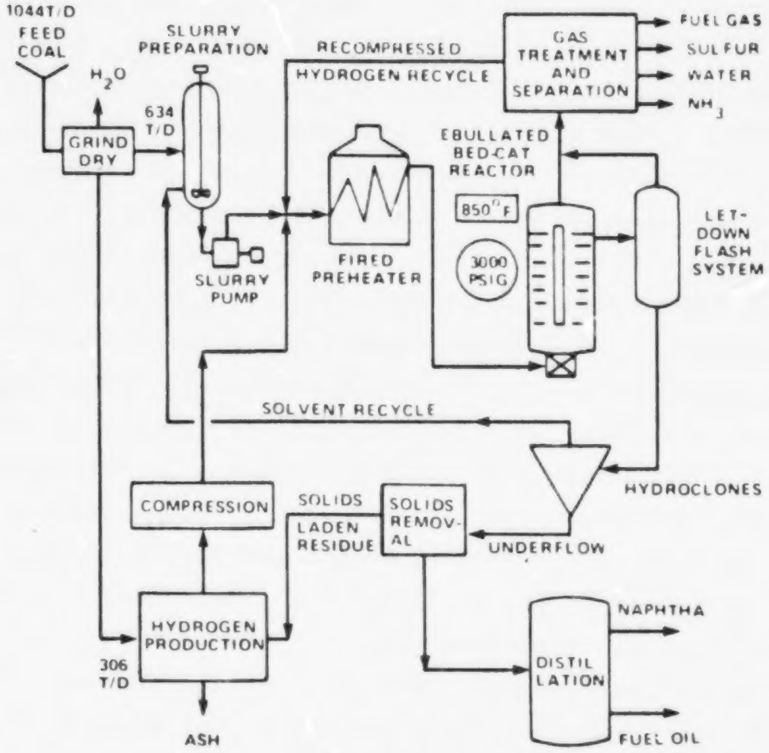

1044T/D
FEED
COAL
SLURRY
PREPARATION
RECOMPRESSED
HYDROGEN RECYCLE
GAS
TREATMENT
AND
SEPARATION
FUEL GAS
SULFUR
WATER
NH3
H2O
634
T/D
GRIND
DRY
EBULLATED
BED-CAT
REACTOR
850° F
3000
PSIG
LET-
DOWN
FLASH
SYSTEM
SLURRY
PUMP
FIRED
PREHEATER
SOLVENT RECYCLE
HYDROCLONES
COMPRESSION
SOLIDS
LADEN
RESIDUE
SOLIDS
REMOV-
AL
UNDERFLOW
HYDROGEN
PRODUCTION
306
T/D
ASH
NAPHTHA
DISTIL
LATION
FUEL OIL

FIGURE B-1

H-COAL PROCESS - PILOT SCALE

(SOURCE: 39, p. 64)

The pilot plant design effort resulted in a preliminary design nine months after the contract began and a 90-percent completed bid-package by March 1976. Construction of the pilot plant started in January 1977, with completion scheduled for late FY 1978. After plant startup, pilot plant operability will be demonstrated in both the syncrude and the boiler fuels modes. Material balance data around all process units will be used to establish process yield data as a function of coal type and operating conditions. (39)

TABLE B-1

SYMBOL DEFINITIONS

△ Begin Milestone

▽ End Milestone

⬡ Decision Milestone

▲ Begin Milestone (Task Completed)

▼ End Milestone (Task Completed)

⬢ Decision Milestone (Decision Made)

● Release Request for Proposals
1 or Program Opportunity Notice

●
2 Proposals Received

●
3 Contractor Selected

●
4 Contract Award

●
5 Order Long-Lead Items

●
6 Final Environmental Impact Statement

↕ Information Transfer

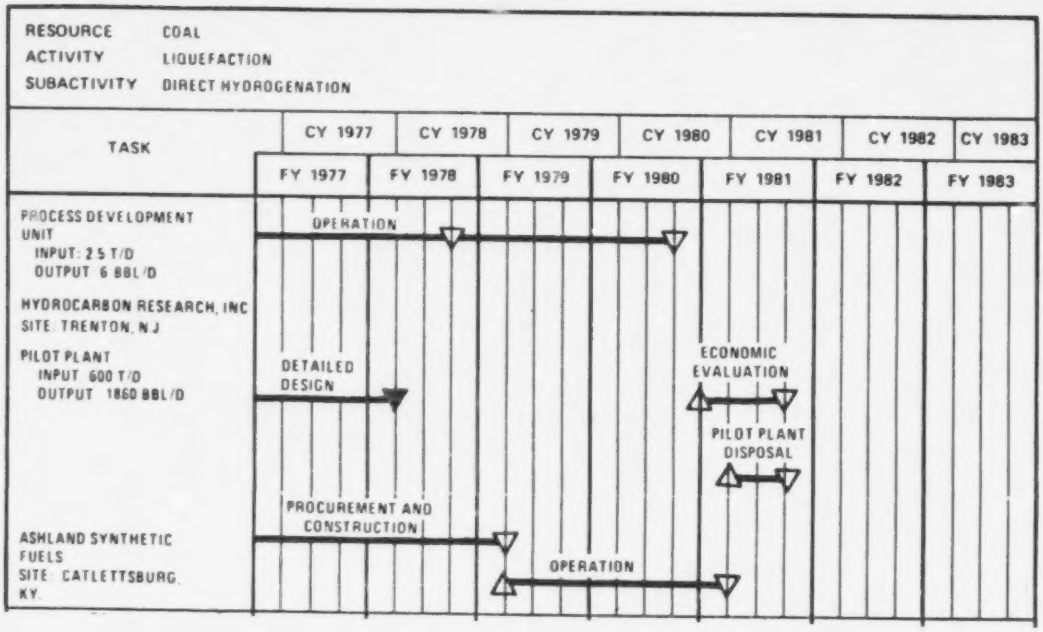


FIGURE B-2

H-COAL PROJECT SCHEDULE*

(SOURCE: 39, p. 65)

*SEE TABLE B-1 FOR SYMBOLS

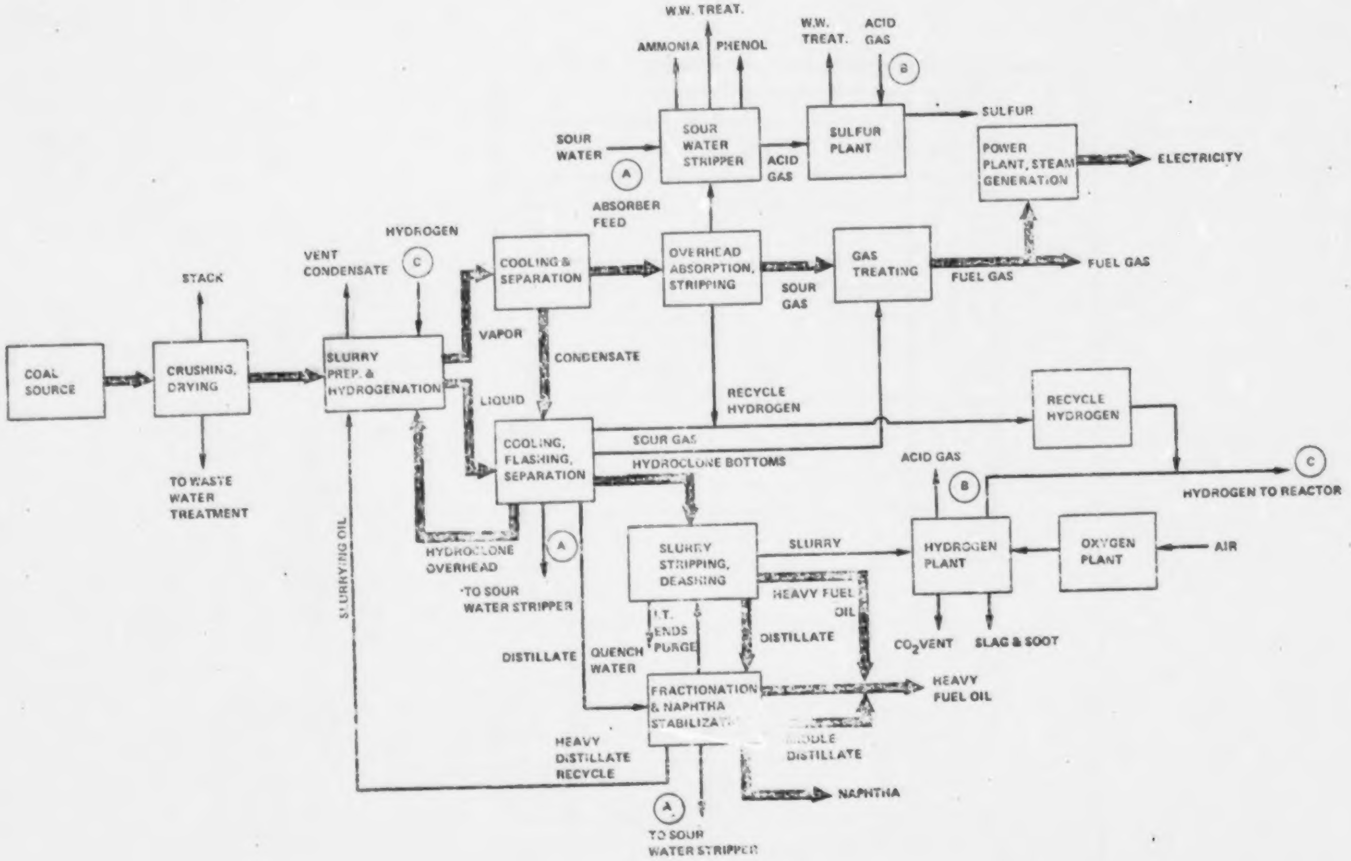

W.W. TREAT.
AMMONIA
PHENOL
W.W. TREAT.
ACID GAS
B
SOUR WATER
A
SOUR WATER STRIPPER
ACID GAS
SULFUR PLANT
SULFUR
POWER PLANT, STEAM GENERATION
ELECTRICITY
ABSORBER FEED
HYDROGEN
VENT CONDENSATE
C
STACK
COOLING & SEPARATION
OVERHEAD ABSORPTION, STRIPPING
SOUR GAS
GAS TREATING
FUEL GAS
FUEL GAS
COAL SOURCE
CRUSHING, DRYING
SLURRY PREP. & HYDROGENATION
VAPOR
LIQUID
CONDENSATE
RECYCLE HYDROGEN
RECYCLE HYDROGEN
TO WASTE WATER TREATMENT
COOLING, FLASHING, SEPARATION
SOUR GAS
HYDROCLONE BOTTOMS
ACID GAS
B
C
HYDROGEN TO REACTOR
SLURRYING OIL
HYDROCLONE OVERHEAD
A
TO SOUR WATER STRIPPER
SLURRY STRIPPING, DEASHING
SLURRY
HYDROGEN PLANT
OXYGEN PLANT
AIR
HEAVY FUEL OIL
LT. ENDS PURGE
DISTILLATE
DISTILLATE
QUENCH WATER
CO_2 VENT
SLAG & SOOT
FRACTIONATION & NAPHTHA STABILIZATI
HEAVY FUEL OIL
HEAVY DISTILLATE RECYCLE
IDDLE DISTILLATE
NAPHTHA
A
TO SOUR WATER STRIPPER

FIGURE B-3

H-COAL PROCESS - COMMERCIAL SCALE

(SOURCE: 58)

SOLVENT REFINED COAL (SRC) PROCESS DESCRIPTION (COMMERCIAL SCALE).

The Solvent Refined Coal (SRC) process produces a low sulfur, low ash, high heating value solid or liquid fuel from high sulfur coals. The coal is pulverized, dried, and mixed in a slurry mix tank to 800°F. The slurry is then mixed with hydrogen, which is produced by other steps in the process, and heated to 850°F at 1,000 psi, causing complete solution of the organic matter, corresponding to about 90 percent of the moisture- and ash-free coal. Hydrogen requirements vary from 15,000 to 80,000 SCF per ton of coal. In the dissolver, the coal is depolymerized and hydrogenated, causing an overall decrease in product molecular weight, and the solvent is hydrocracked to form lower molecular weight hydrocarbons ranging from methane to light oil. The organic sulfur is hydrogenated to form hydrogen sulfide. Gas from the dissolver is separated in a high-pressure flash vessel operating at 995 psi and 625°F. The raw gas is sent to a hydrogen recovery and gas desulfurization unit. The hydrogen recovered is recycled for mixing with the slurry, and the hydrogen sulfide is converted to elemental sulfur in a Claus plant. The slurry of undissolved solids and the coal solution from the flash vessel pass to a filtration unit where the undissolved solids are removed and sent to a gasifier-converter where they react with supplemental coal, steam, and oxygen to produce hydrogen for use in the process. The coal solution passes to the solvent recovery unit and the final product, solvent refined coal, is produced. The product has a solidification point of 350 to 400°F and a heating value of about 16,000 Btu per pound. Typical properties of solvent refined coal obtained from a western Kentucky bituminous coal having 7.1 percent ash and 3.4 percent sulfur is a fuel containing 0.1 percent ash and 0.8 percent sulfur. The product can be transported hot (400°F) as a liquid fuel or at ambient temperature as a solid fuel.

Sulfur-containing gas streams from the process are sent through a monoethanolamine (MEA) acid-gas treatment facility to recover the sulfur in the form of hydrogen sulfide. Although the MEA system will not remove carbonyl sulfide, it is expected to be negligible because of the high water vapor to carbon dioxide ratio present. The hydrogen sulfide is then converted to elemental sulfur in a Claus plant, followed by a SCOT tail gas cleanup system. The overall sulfur recovery from the plant is expected to exceed 94 percent of the entering sulfur. The liquid waste streams will contain phenol and cresylic acids. The cresylic acids are reduced to about 100 ppm by a combination of solvent extraction and stripping and the cresylic acid is then recovered from the solvent by distillation and, if necessary, extraction. Process water is filtered through activited carbon which adsorbs cresylic acids and phenol, which are subsequently regenerated by stripping with 200 psi steam. The stripped acids are reprocessed in the recovery plant. Alternatives include passing the wastewater through a mineral residue gasifier which destroys the cresylic acids and phenol. Process water runoff goes to holding ponds for further treatment by skimming and reaction. (5)

Developer. Pittsburgh and Midway Coal Mining Company (PAMCO), an affiliate of Spencer Chemical.

Status. Two SRC pilot plants are currently in operation. The objective of the 50 ton per day plant at Ft. Lewis, WA., is to generate data which will provide a basis for the engineering design and economic feasibility study of commercial scale SRC plants. The objective of the six ton per day plant at Wilsonville, Al., is to provide a flexible test unit for screening additional coals and for selecting among various processing options for further testing at Ft. Lewis.

The SRC process has been selected as a new demonstration project in FY 1978 because: 1) the technology is the most mature of the liquefaction processes; 2) the pilot plant has operated successfully, making solid and liquid fuels; and 3) the preliminary economical evaluations indicate that the process is competitive with other liquefaction processes. It provides an attractive route of conversion

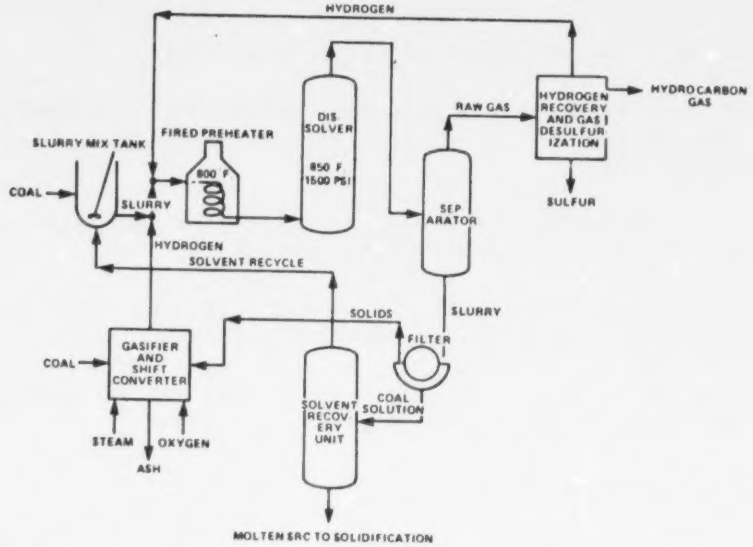

HYDROGEN
DISSOLVER
850 F
1500 PSI
HYDROGEN RECOVERY AND GAS DESULFURIZATION
HYDROCARBON GAS
RAW GAS
FIRED PREHEATER
800 F
SLURRY MIX TANK
COAL
SLURRY
SEPARATOR
SULFUR
HYDROGEN
SOLVENT RECYCLE
SOLIDS
SLURRY
FILTER
GASIFIER AND SHIFT CONVERTER
COAL
COAL SOLUTION
SOLVENT RECOVERY UNIT
STEAM
OXYGEN
ASH
MOLTEN SRC TO SOLIDIFICATION

FIGURE B-4

SRC (SOLID) PROCESS - PILOT SCALE

(SOURCE: 39, p. 100)

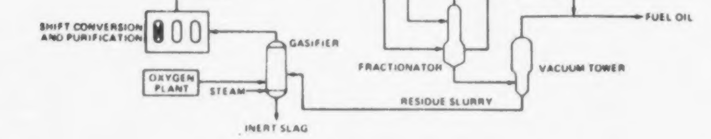

PURIFIED HYDROGEN
VAPOR LIQUID SEPARATORS
CRYOGENIC SEPARATION
PIPELINE GAS
DISSOLVER
SLURRY MIXING TANK
DRIED PULVERIZED COAL
SLURRY PREHEATER
LPG
ACID GAS REMOVAL
PRODUCT SLURRY
LIGHT LIQUID
RECIPROCATING PUMP
SULFUR
LIGHT DISTILLATE
MAKE UP HYDROGEN
FUEL OIL
SHIFT CONVERSION AND PURIFICATION
GASIFIER
FRACTIONATOR
VACUUM TOWER
OXYGEN PLANT
STEAM
RESIDUE SLURRY
INERT SLAG

FIGURE B-5

SRC (LIQUID) PROCESS - PILOT SCALE

(SOURCE: 39, p. 101)

of high-sulfur coal to an environmentally acceptable clean-burning synthetic fuel. An SRC demonstration plant will:

- Provide an accurate basis for determining investment and operation costs for commercial-sized applications of this technology
- Prove the environmental acceptability of this fuel product for direct use in electric power generation
- Assess the marketability of a range of fuel products obtainable from a given coal and process
- Confirm the acceptability by utilities and industries of this fuel product with minimum burner retrofit
- Demonstrate the technical viability of the process by operating full-scale solid/liquid separation, hydrogen generation and residue extraction systems, as well as by increasing confidence in the improved metals, design, and fabrication technologies needed for commercial-scale applications.

Conceptual design of SRC demonstration plants has been initiated by proponents and can be finalized immediately upon contract award. Design of an SRC demonstration plant could begin in the first quarter of FY 1979. (5)

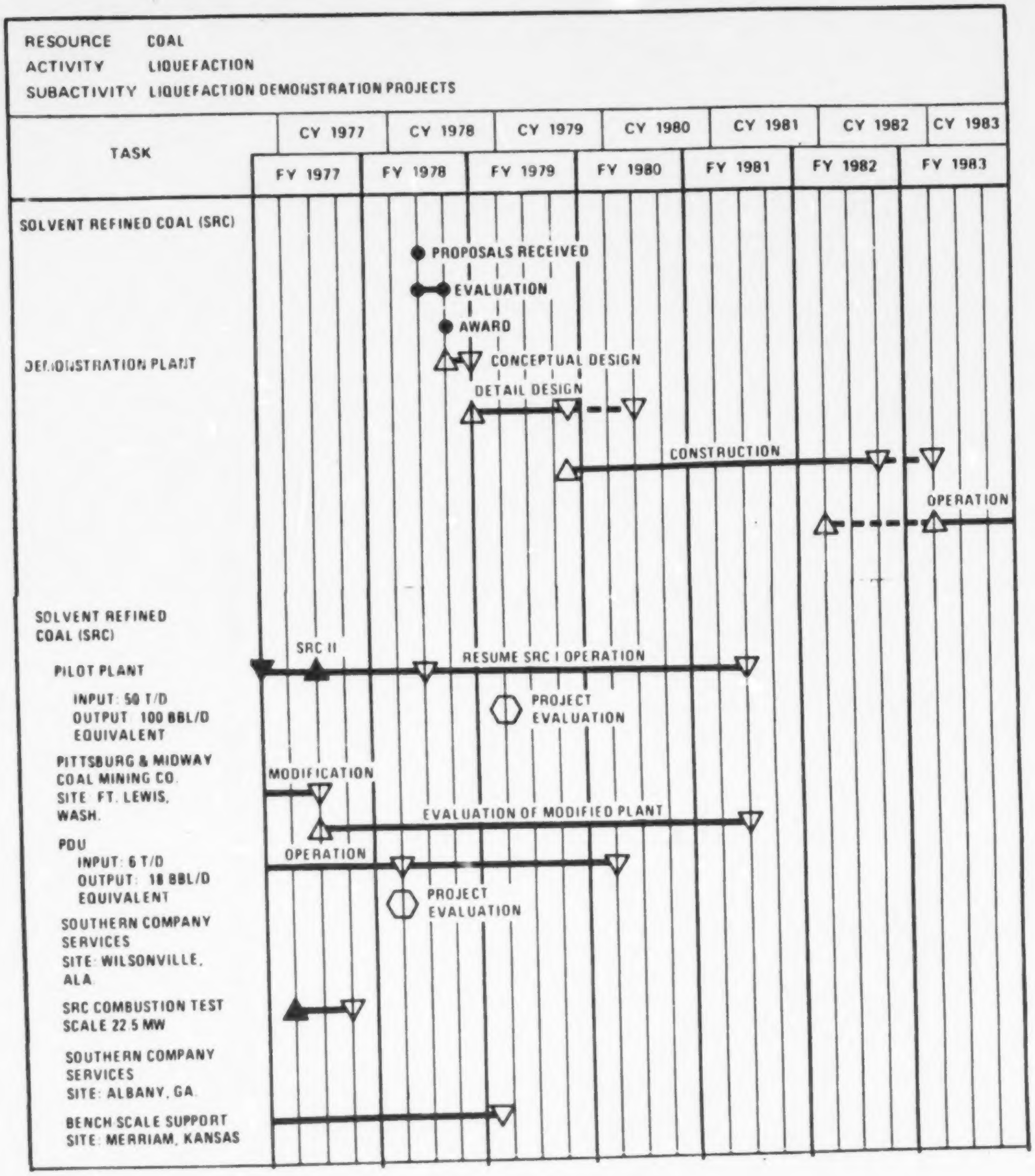


FIGURE B-6

SRC PROCESS PROJECT SCHEDULE

(SOURCE: 39, p. 78 and 102)

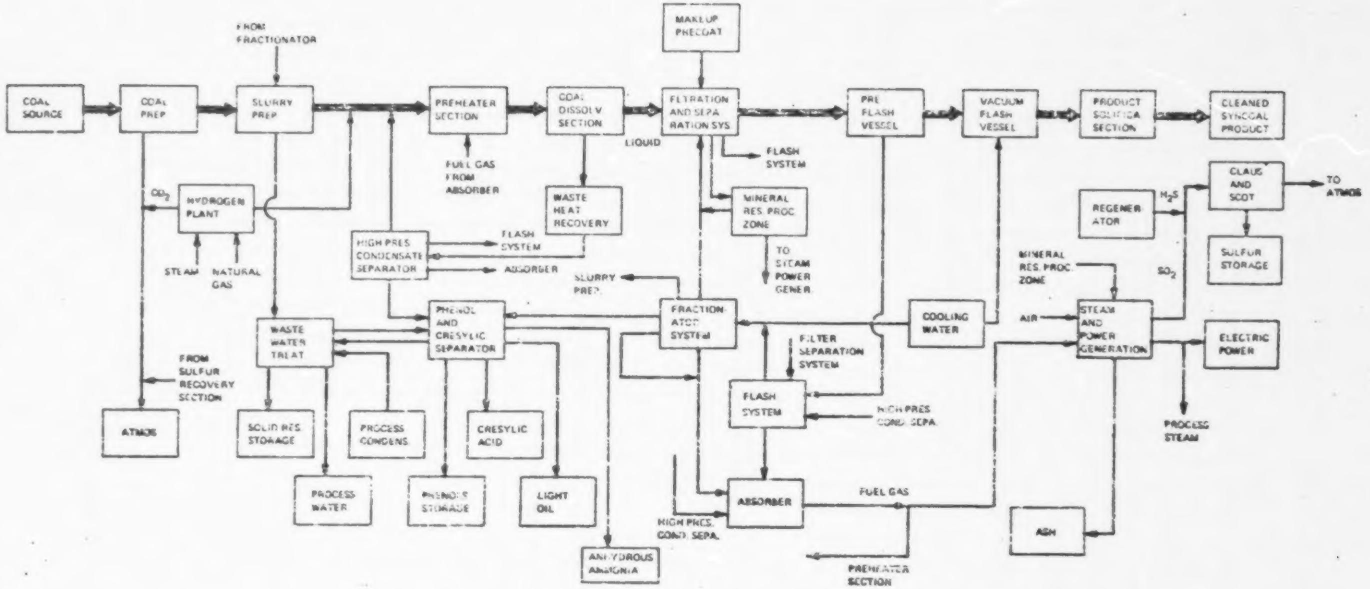

FROM FRACTIONATOR
COAL SOURCE
COAL PREP
SLURRY PREP
PREHEATER SECTION
COAL DISSOLV SECTION
MAKEUP PRECOAT
FLTRATION AND SEPA RATION SYS.
LIQUID
PRE FLASH VESSEL
VACUUM FLASH VESSEL
PRODUCT SOLIFICA SECTION
CLEANED SYNCOAL PRODUCT
CO_2
HYDROGEN PLANT
STEAM
NATURAL GAS
FUEL GAS FROM ABSORBER
WASTE HEAT RECOVERY
HIGH PRES CONDENSATE SEPARATOR
FLASH SYSTEM
ABSORBER
FLASH SYSTEM
MINERAL RES PROC ZONE
TO STEAM POWER GENER.
SLURRY PREP.
FRACTION ATOR SYSTEM
PHENOL AND CRESYLIC SEPARATOR
WASTE WATER TREAT
FROM SULFUR RECOVERY SECTION
ATMOS
SOLID RES STORAGE
PROCESS CONDENS
CRESYLIC ACID
PROCESS WATER
PHENOLS STORAGE
LIGHT OIL
ANHYDROUS AMMONIA
HIGH PRES. COND. SEPA.
FILTER SEPARATION SYSTEM
FLASH SYSTEM
HIGH PRES COND. SEPA.
ABSORBER
FUEL GAS
PREHEATER SECTION
COOLING WATER
REGENER ATOR
H_2S
CLAUS AND SCOT
TO ATMOS
SULFUR STORAGE
SO_2
MINERAL RES. PROC. ZONE
AIR
STEAM AND POWER GENERATION
ELECTRIC POWER
PROCESS STEAM
ASH

FIGURE B-7

SOLVENT REFINED COAL PROCESS - COMMERICAL SCALE

(SOURCE: 64 and 77)

EXXON DONOR SOLVENT PROCESS DESCRIPTION (PILOT PLANT SCALE)

This process is proprietary (Exxon) and no particulars are available for release at this time.

The process converts coal to liquid fuel products. The processing sequence is designed to allow for different coal feeds as well as product distribution. A hydrogenated recycle solvent produced by selective catalytic hydrogenation of the middle product fraction is incorporated in the process.

In the liquefaction reactor, coal, recycle solvent and hydrogen are reacted to produce gas, raw coal liquids, and a heavy bottoms stream which contains the unreacted coal and mineral matter. The liquefaction step effluent is separated via distillation in the separation block and the recycle solvent is catalytically hydrogenated in the solvent hydrogenation block to produce rejuvenated solvent. The heavy bottoms from the distillation section are further processed to produce additional liquids and hydrogen or fuel gas in the hydrogen manufacturing block. The gas generated from the process is used as fuel and for H_2 manufacture. Depending upon the ultimate product utilization, the raw coal liquids may be further hydrotreated. (5)

Developer. Exxon Research and Engineering.

Status.

During FY 1979, work emphasis will be as follows:

- Completion of detailed engineering and procurement for the pilot plant
- Construction of the pilot plant
- Preparation for pilot plant operation
- Operation on the third coal to be evaluated in the pilot plant
- Investigation of liquefaction/bottoms processing interactions
- Evaluation of process improvements
- Performance of liquefaction studies using model compounds
- Study of coal liquids compatability and storage behavior

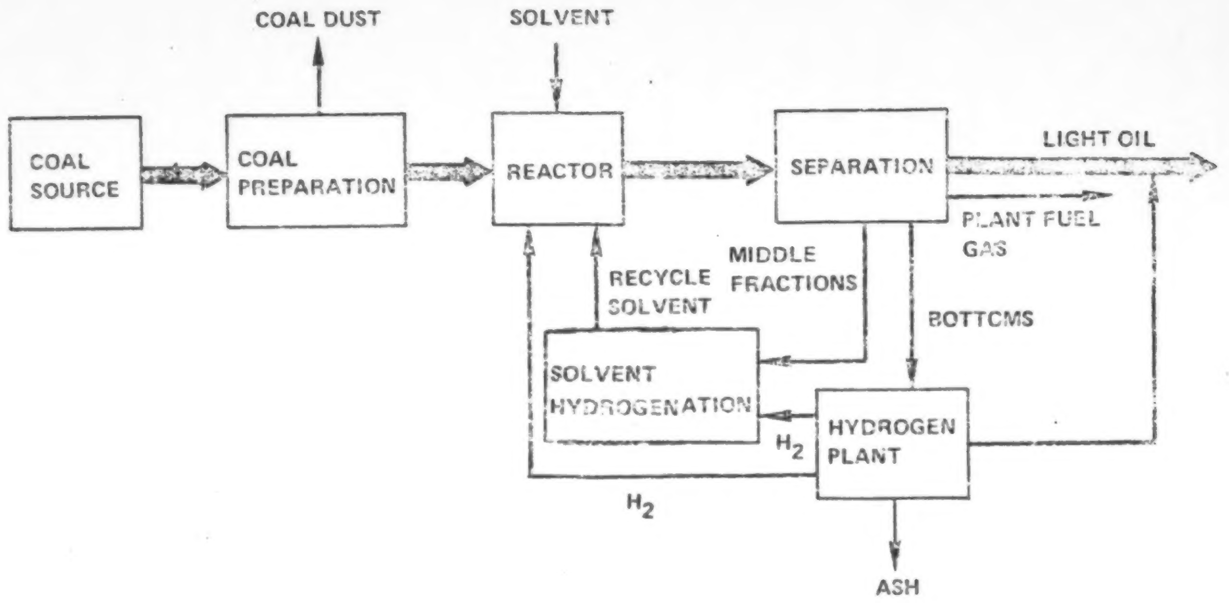

COAL DUST
SOLVENT
COAL SOURCE
COAL PREPARATION
REACTOR
SEPARATION
LIGHT OIL
PLANT FUEL GAS
MIDDLE FRACTIONS
RECYCLE SOLVENT
BOTTOMS
SOLVENT HYDROGENATION
HYDROGEN PLANT
H_2
H_2
ASH

FIGURE B-8

EXXON DONOR SOLVENT LIQUEFACTION PROCESS
(PDU/PILOT PLANT SCALE)

(SOURCE: 5, p. A-43)

- Development of mathematical model to describe coking of coal-derived feed
- Performance of coke gasification studies
- Investigation of fluid coking and coke gasification operability limits
- Performance of studies for noncoking bottoms processing options
- Investigation of fluid coking and FLEXICOKING operability in the 2-bbl/d integrated coker gasifier
- Planning of the pilot plant operation program
- Preparation of pilot plant startup procedures
- Preparation of plant for orderly takeover of pilot plant equipment from construction contractor
- Characterization of air and water emissions and evaluation of control techniques
- Preparation of industrial hygiene plan for pilot plant operating personnel
- Performance of studies on coal-derived liquids and emissions to support industrial hygiene plan
- Pressuration and operation of equipment in preparation for pilot plant startup
- Preparation of conceptual study design
- Evaluation of alternative methods of processing the coke scrubber liquids
- Evaluation of slurry dryer/mixer.

The major effort in FY 1979 will be completion of detailed engineering and procurement and the start of construction. The primary thrust in FY 1980 will be completion of construction and the start of shakedown and operation, with the latter planned to end in FY 1982. (39)

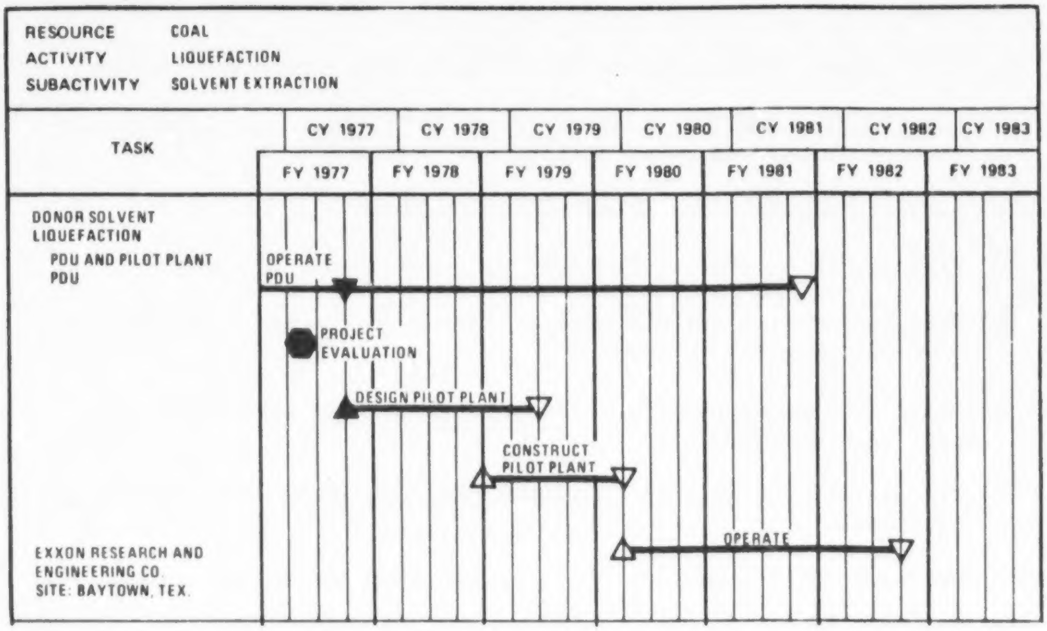


FIGURE B-9

EXXON DONOR SOLVENT PROJECT SCHEDULE

(SOURCE: 39, p. 84)

ENTRAINED PYROLYSIS PROCESS DESCRIPTION (COMMERCIAL SCALE)

This process is designed to eliminate the tendency of some coals to agglomerate. Char particles in an entrained state are mixed with hot coal particles to prevent this tendency. The coal milling operation is complex because of the need to control particle size. The control problem is less severe with sub-bituminous coal than with bituminous coal.

During the preparation stage, raw coal is fed into hammermills for reduction to a maximum nominal size (one-eighth inch for subbituminous). Crushed dried coal is conveyed by recycle product gas to the pyrolysis reactor, an entrained bed carbonizer, operating at 1100°F. Char is separated from the pyrolysis gas by cyclones. A portion of the char is cooled to be product char; the remainder is fed to the char heater where it is burned with air to about 1400°F. The heated char is recycled to the pyrolysis reactor.

The pyrolysis gas is essentially freed of fine char entrainment prior to quenching in the tar collection system. A portion of the gas stream is used for conveying the feed coal and recycled char to the pyrolysis reactor. After acid gas removal some of the gas is taken as product gas; the rest is used to produce hydrogen which in turn is used to hydrotreat tar to obtain synthetic crude oil.

Developer. Occidental Research Corporation, LaVerne, CA.

Status. A PDU has been operating at LaVerne since mid-1976. (5)

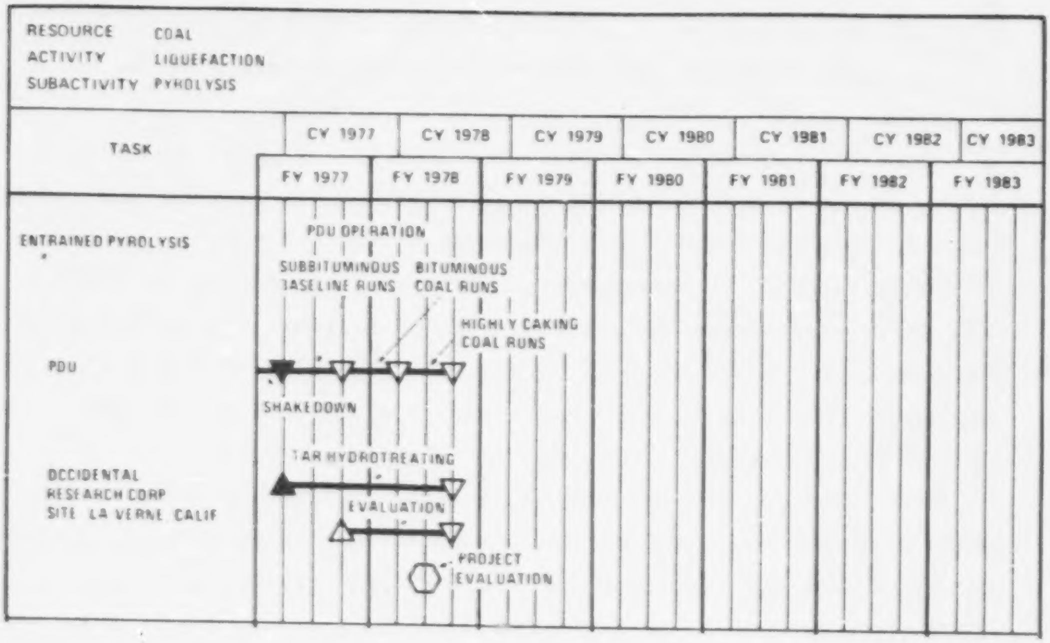

RESOURCE COAL
ACTIVITY LIQUEFACTION
SUBACTIVITY PYROLYSIS
TASK
CY 1977
CY 1978
CY 1979
CY 1980
CY 1981
CY 1982
CY 1983
FY 1977
FY 1978
FY 1979
FY 1980
FY 1981
FY 1982
FY 1983
ENTRAINED PYROLYSIS
PDU OPERATION
SUBBITUMINOUS BASELINE RUNS
BITUMINOUS COAL RUNS
HIGHLY CAKING COAL RUNS
PDU
SHAKEDOWN
TAR HYDROTREATING
OCCIDENTAL RESEARCH CORP SITE LA VERNE CALIF
EVALUATION
PROJECT EVALUATION

FIGURE B-10

ENTRAINED PYROLYSIS PROJECT SCHEDULE

(SOURCE: 39, p. 87)

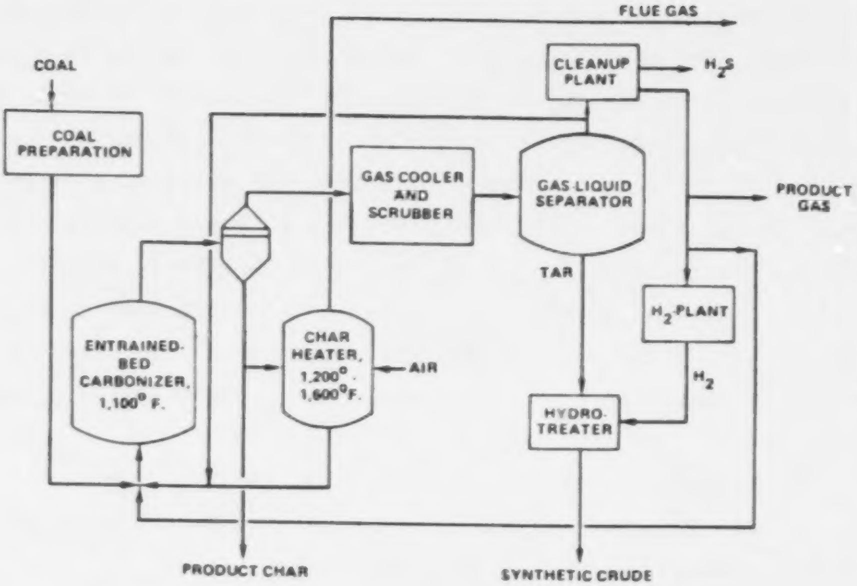

FLUE GAS
COAL
CLEANUP PLANT
H_2S
COAL PREPARATION
GAS COOLER AND SCRUBBER
GAS-LIQUID SEPARATOR
PRODUCT GAS
TAR
H_2-PLANT
ENTRAINED-BED CARBONIZER, 1,100° F.
CHAR HEATER, 1,200°-1,600°F.
AIR
H_2
HYDRO-TREATER
PRODUCT CHAR
SYNTHETIC CRUDE

FIGURE B-11

ENTRAINED PYROLYSIS PROCESS - PDU SCALE

(SOURCE: 39, p. 86)

BIGAS PROCESS DESCRIPTION (COMMERCIAL SCALE)

The BIGAS process is an advanced coal gasification system which uses pulverized coal to produce high-Btu, pipeline gas. Coal is cleaned, crushed, and dried to 1.3 percent moisture. Since the gasifier operates at 80 atmospheres, it is necessary to pressurize the coal feed. The coal is gasified using steam and oxygen in a two zone reactor at 80 atmospheres. Operation of the reactor is based on entrained flow rather than using a fluidized-bed or fixed-bed reactor. Coal is fed to the top (1700°F) zone where it mixes with steam and hot synthesis gas entering from the lower zone. Conditions in this upper zone favor high formation of methane, with negligible amounts of tar or oil. Although the volatile content of the coal feed is completely consumed, there is considerable unreacted char remaining which is carried out with the gas and recovered by cyclones following the reactor.

The char is recycled to the lower gasification zone where is it reacted with steam and oxygen at 3000°F. Slag is withdrawn from the bottom, quenched with water, and removed.

Hot raw gas from the gasifier passes to cyclone separators which remove most of the char and solid particles in the gas. The quenched gas still contains some dust that was not removed by the cyclones, but must be removed so as not to plug the fixed bed of shift conversion catalyst. Rather than scrub the dust out with water, which would require considerable cooling, the dust is filtered out at high temperature using sand beds. Entrained dust from back flushing is then returned to the gasifier where it leaves with the slag.

After dust removal, the gas next goes to a shift converter where carbon monoxide reacts with steam to form hydrogen and carbon dioxide, increasing the ratio of H_2 to CO to three to one as required in the final methanation.

After shift conversion, the gas is cooled to remove most of the remaining moisture. This, of course, produces sour water containing

H_2S and ammonia and possibly traces of cyanides and phenols. Removal of all sulfur compounds is needed to meet pipeline gas specifications and to protect the methanation catalyst. The bulk of the sulfur compounds is needed to meet pipeline gas specifications and to protect the methanation catalyst. The bulk of the sulfur, as well as CO_2, is removed using the proprietary Benefield process based on hot carbonate scrubbing. Two separate absorber towers are used in series. The first of these produces a gas relatively high in sulfur content, about 8 percent H_2S, to facilitate sulfur recovery in the Claus plant. The second absorber is for the final cleanup of sulfur from the gas and for CO_2 removal.

Most of the CO_2 is removed in this second absorber and vented to the air; however, this CO_2 vent stream contains excessive amounts of H_2S, and further processing is needed to clean it up. Therefore, adsorption using molecular sieves has been provided to recover the H_2S content and send it to the Claus sulfur plant.

Gasification produces many compounds in addition to H_2S, such as cyanides and thiocyanates as well as large amounts of ammonia. There are also various sulfur compounds, particularly carbonyl sulfide and some carbon disulfide. It is essential to completely remove all of these before methanation in order to protect catalyst activity. Most of the ammonia and compounds that are highly soluble in water will be removed in the condensation after shift conversion.

After acid gas removal, clean synthesis gas is methanated to increase the heating value of the gas up to pipeline quality. The reaction of CO with 3 volumes of H_2 to make methane and water can be carried out in a fixed bed of nickel catalyst. A guard bed of zinc oxide ahead of the reactor removes traces of sulfur compounds in order to protect the methanation of catalyst. Waste water is treated where phenol and ammonia are recovered, process water is recycled, and a solid residue is generated. (5)

Developer. Bituminous Coal Research, Inc., Monroeville, PA.

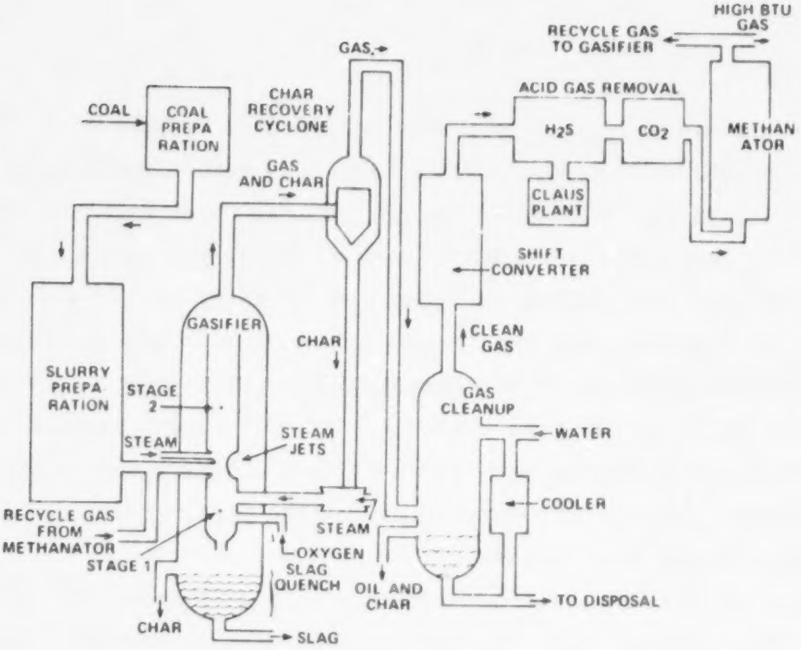

HIGH BTU GAS
RECYCLE GAS TO GASIFIER
GAS
ACID GAS REMOVAL
COAL
COAL PREPARATION
CHAR RECOVERY CYCLONE
H_2S
CO_2
METHANATOR
GAS AND CHAR
CLAUS PLANT
SHIFT CONVERTER
GASIFIER
CHAR
CLEAN GAS
SLURRY PREPARATION
STAGE 2
GAS CLEANUP
STEAM
STEAM JETS
WATER
COOLER
RECYCLE GAS FROM METHANATOR
STEAM
OXYGEN
STAGE 1
SLAG QUENCH
OIL AND CHAR
TO DISPOSAL
CHAR
SLAG

FIGURE B-12

BI-GAS PROCESS - PILOT SCALE

(SOURCE: 39, p. 110)

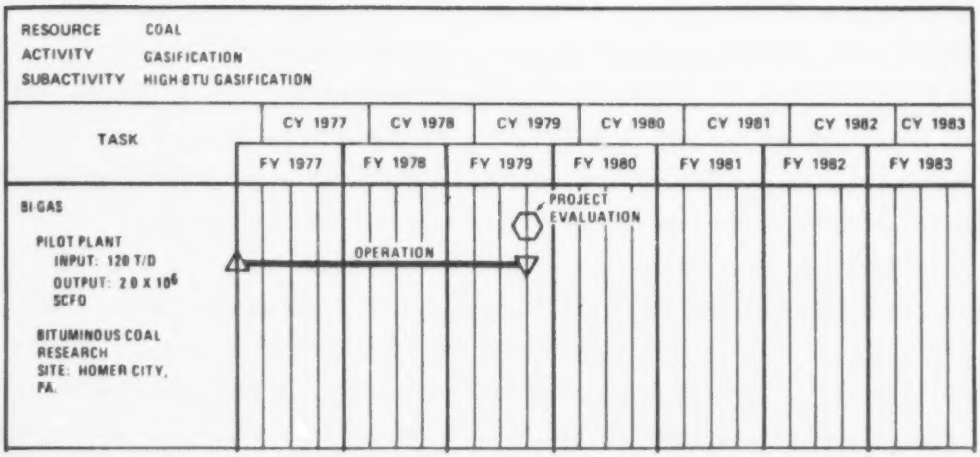

RESOURCE COAL
ACTIVITY GASIFICATION
SUBACTIVITY HIGH-BTU GASIFICATION

FIGURE B-13

BI-GAS PROCESS PROJECT SCHEDULE

(SOURCE: 39, p. 111)

Status. A 120-tons/day pilot plant was constructed by Stearns-Rogers, Inc., at Homer City, Pennsylvania, in FY 1976. Shakedown and startup activities were started in FY 1976. Phillips Petroleum Company has the overall responsibility for planning and conducting the pilot plant research program, which will run for approximately three years. At the end of FY 1979, a decision will be made to continue operation into FY 1980 or to discontinue the operation.

Pilot plant support work will be carried out at the facilities of BCR in Monroeville, Pennsylvania. Slag viscosity measurements, slag behavior with and without additives, and catalyst evaluation for the fluidized-bed methanation system are among the support tasks. The Bi-Gas pilot plant operation will generate scaleup parameters for the design of a commercial-size demonstration plant. (39)

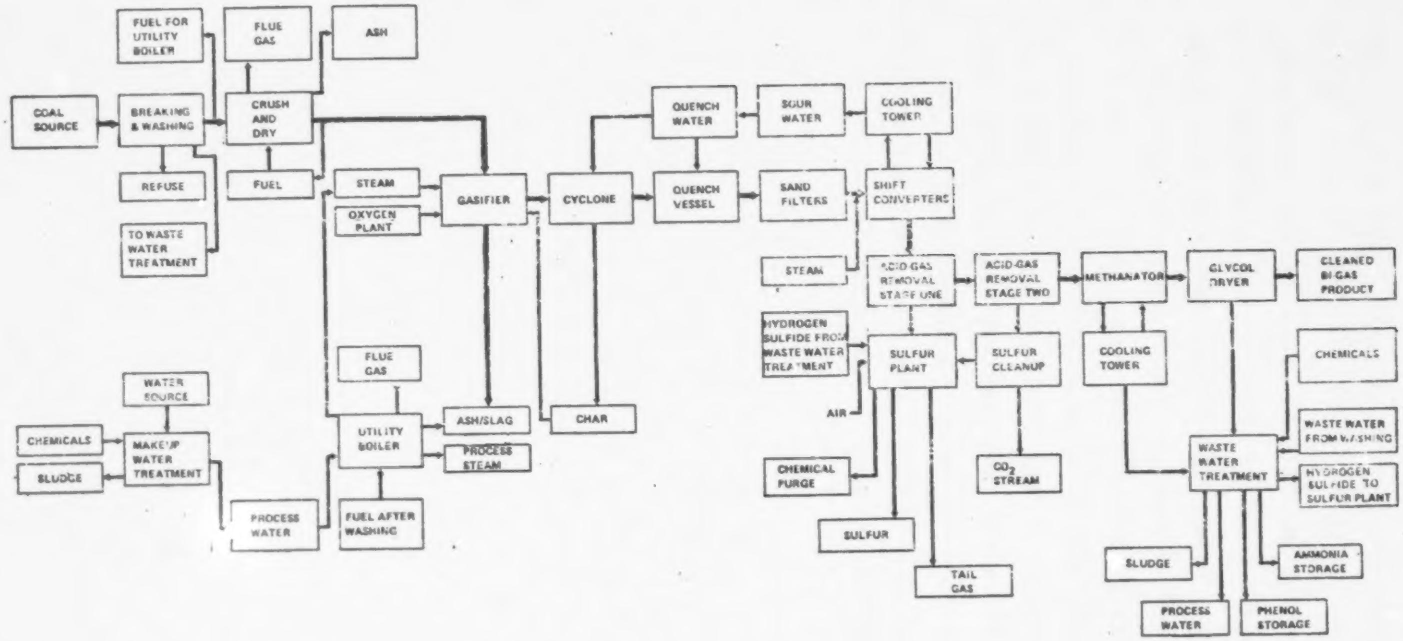

FUEL FOR UTILITY BOILER
FLUE GAS
ASH
COAL SOURCE
BREAKING & WASHING
CRUSH AND DRY
REFUSE
FUEL
TO WASTE WATER TREATMENT
STEAM
OXYGEN PLANT
GASIFIER
CYCLONE
QUENCH WATER
QUENCH VESSEL
SOUR WATER
SAND FILTERS
COOLING TOWER
SHIFT CONVERTERS
STEAM
ACID-GAS REMOVAL STAGE ONE
ACID-GAS REMOVAL STAGE TWO
METHANATOR
GLYCOL DRYER
CLEANED BI-GAS PRODUCT
HYDROGEN SULFIDE FROM WASTE WATER TREATMENT
SULFUR PLANT
SULFUR CLEANUP
COOLING TOWER
CHEMICALS
AIR
WATER SOURCE
FLUE GAS
CHEMICALS
MAKE-UP WATER TREATMENT
SLUDGE
UTILITY BOILER
ASH/SLAG
PROCESS STEAM
CHAR
PROCESS WATER
FUEL AFTER WASHING
CHEMICAL PURGE
SULFUR
TAIL GAS
CO_2 STREAM
WASTE WATER TREATMENT
WASTE WATER FROM WASHING
HYDROGEN SULFIDE TO SULFUR PLANT
SLUDGE
AMMONIA STORAGE
PROCESS WATER
PHENOL STORAGE

FIGURE B-14

BI-GAS PROCESS - COMMERCIAL SCALE

(SOURCE: 54)

HYGAS PROCESS DESCRIPTION (COMMERCIAL SCALE)

The HYGAS process is an advanced coal gasification system that can use all domestic coals, including high volatile, bituminous feeds, to produce a high-Btu pipeline gas. Coal is dried, crushed, and slurried with a process-derived oil and compressed to over 1,000 psi. The slurry is then moved into the slurry drier section of the hydrogasifier.

The four-section hydrogasifier includes the slurry drier in which the slurry is sprayed on a fluidized bed. The oil is flashed and removed along with the hot process gases rising through the bed from the lower stages of the gasifier. Flashed oil is recovered by quenching and is reused. The dried coal is routed to the first stage of the gasifier located below the drier coal and above the second stage. The coal enters the gasifier at mid-height and is heated to 1,200° - 1,400°F by the hot reaction gas from the second stage. The first stage (1,200°F, 1,000 psi) favors the direct production of methane from the coal (about 20 percent). Solids are channeled to the second stage, where rising gases contact the char for further gasification at 1,500° to 1,800°F. Unreacted char and ash drop into the steam-oxygen gasifier for final gasification, producing a hydrogen-rich gas and steam mixture.

The raw gas leaves at the top of the slurry drying section through a quench which removes dusts, the slurry oil and excess steam. The acid removal system consists of a diglycolamine-water scrub followed by a caustic was and water wash. Carbon dioxide and nitrogen sulfide removal are essentially complete after the amine scrub.

A shift converter adjusts the hydrogen to carbon monoxide ratio to the three-to-one ratio needed for complete conversion of carbon monoxide into methane. Methanation is carried out in two packed-bed downflow reactors. Heat release control is by the Institute of Gas Technology (IGT) split-flow recycle gas to one part feed gas.

The environmental control process for removal of sulfur from the product gas stream consists of a Rectisol solvent based acid gas treating system which reduces the hydrogen sulfide content from 14,400 ppm to about 0.1 ppm and the carbon dioxide content from 30.85 percent to 0.14 percent. Final traces of sulfur are then removed by a fixed bed sulfur guard chamber to reduce sulfur content to less than 0.1 ppm. Hydrogen sulfide is converted to elemental sulfur by treatment in a Claus plant. Twenty percent of the total coal feed to the plant is gasified in the IGT U-Gas process where it is cleaned of sulfur for use as a fuel to generate power, raise steam, and other plant needs, thus reducing the sulfur content in the combustion gases.

The coal fines resulting from the coal crushing, drying, and transportation operations are recovered by cyclone separators and bag filters and returned to the process. Ash from the steam-oxygen gasifier and the U-Gas reactor is extracted from settling ponds and eventually disposed of in the mine. Wastewater from the water scrubbing operations is passed through flash dryers, a Phenosolvan process, strippers, a Phosam process, and two-stage biological treatment where phenol and ammonia are recovered, process water is recycled, and solid residue is generated. (5)

Developer. IGT, Chicago, IL.

Status. An 80 tons per day pilot plant has been in operation since 1971. In July 1976, 640 tons of high sulfur, caking bituminous coal were gasified on a self-sustained basis over a nine-day period. In this run, to prevent caking, the coal was pretreated at 800°F.

Since the operation of the pilot plant was started in 1971, the principal objectives of the project have been achieved. These milestones include: successful processing of lignite, Illinois 6 bituminous (high freeswelling index-7), and subbituminous coals into a Btu gas; demonstration of key-process concepts, as well as key unit operations; and integrated operation of all plant components over a long period of time. It is planned to operate the HYGAS pilot plant for an additional 15 months (beyond June 30, 1977) for the specific purpose of generating the data base required for optimization of a demonstration plant design for the production of pipeline gas from

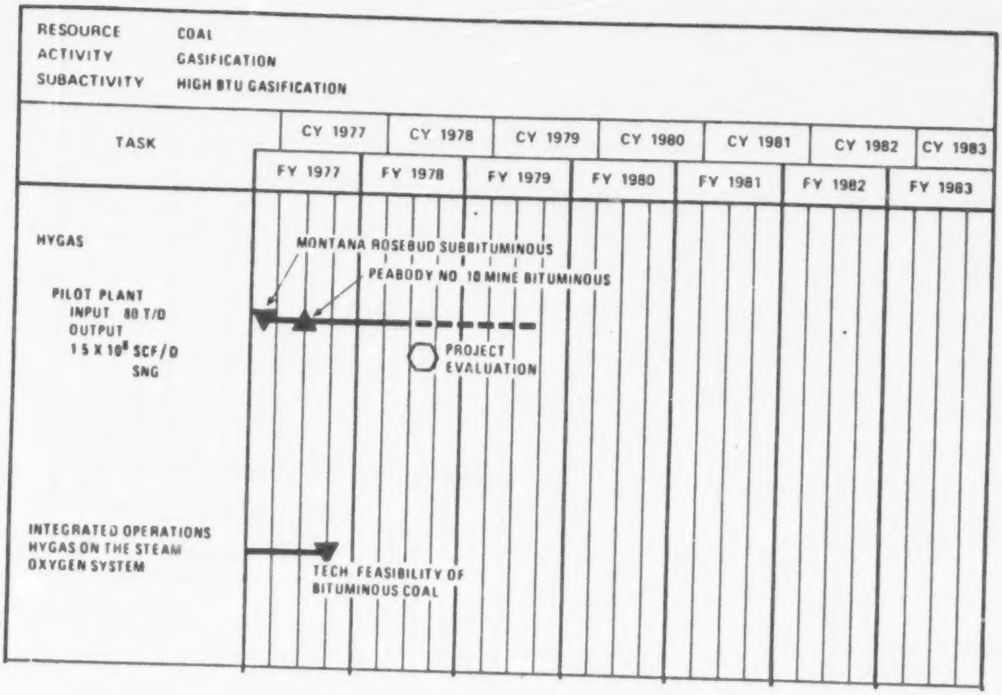


FIGURE B-15

HYGAS PILOT PROJECT SCHEDULE

(SOURCE: 39, p. 109)

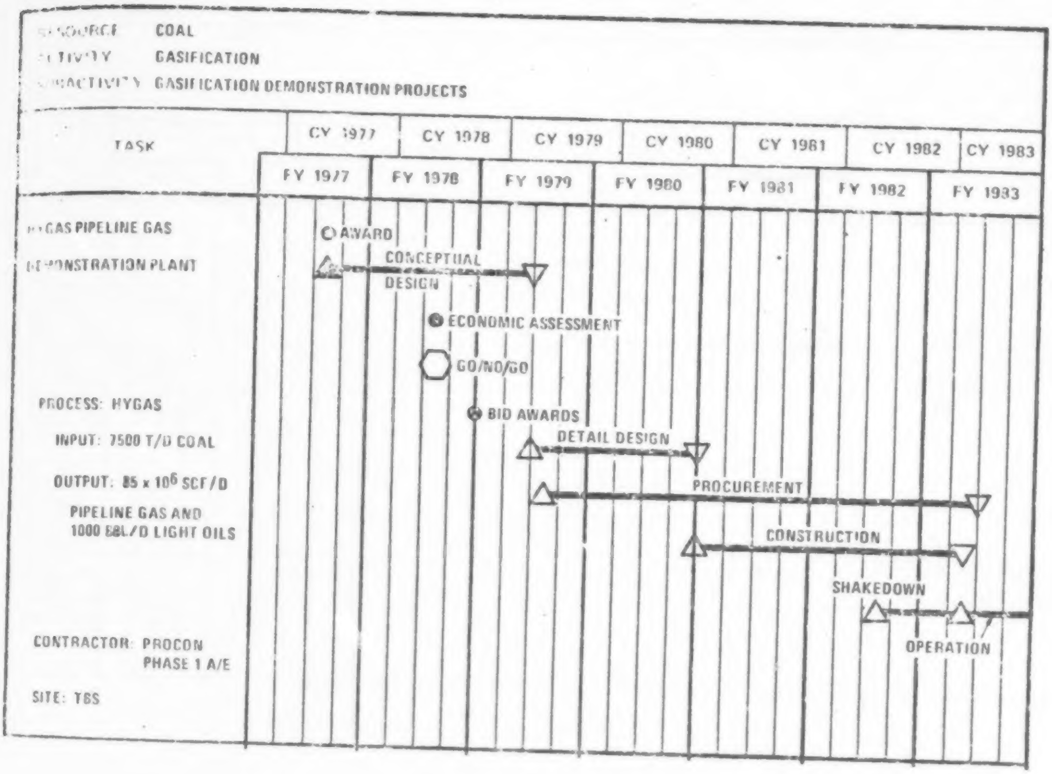


FIGURE B-16

HYGAS DEMONSTRATION PROJECT SCHEDULE

(SOURCE: 39, p. 181)

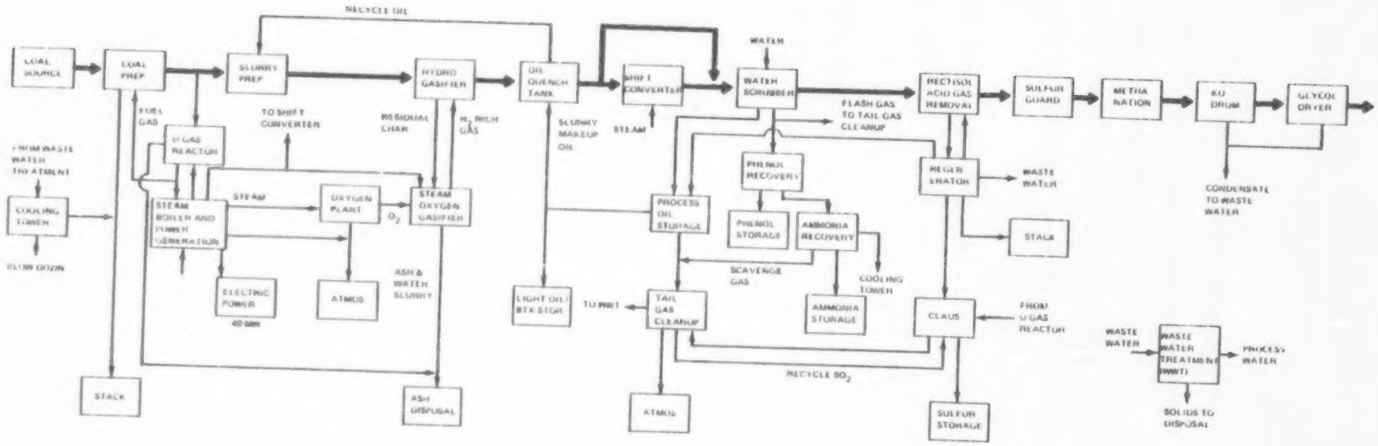

RECYCLE OIL
COAL SOURCE
COAL PREP
SLURRY PREP
HYDRO GASIFIER
OIL QUENCH TANK
SHIFT CONVERTER
WATER
WATER SCRUBBER
RECTISOL ACID GAS REMOVAL
SULFUR GUARD
METHA NATION
KO DRUM
GLYCOL DRYER
FUEL GAS
U-GAS REACTOR
TO SHIFT CONVERTER
RESIDUAL CHAR
H_2 RICH GAS
SLURRY MAKEUP OIL
STEAM
FLASH GAS TO TAIL GAS CLEANUP
FROM WASTE WATER TREATMENT
COOLING TOWER
BLOW DOWN
STEAM BOILER AND POWER GENERATION
STEAM
OXYGEN PLANT
O_2
STEAM OXYGEN GASIFIER
PHENOL RECOVERY
PROCESS OIL STORAGE
PHENOL STORAGE
AMMONIA RECOVERY
REGEN ERATOR
WASTE WATER
CONDENSATE TO WASTE WATER
STACK
ELECTRIC POWER
40 MW
ATMOS
ASH & WATER SLURRY
LIGHT OIL/ BTX STGR
TO WWT
TAIL GAS CLEANUP
SCAVENGE GAS
COOLING TOWER
AMMONIA STORAGE
CLAUS
FROM U-GAS REACTOR
WASTE WATER
WASTE WATER TREATMENT (WWT)
PROCESS WATER
RECYCLE SO_2
STACK
ASH DISPOSAL
ATMOS
SULFUR STORAGE
SOLIDS TO DISPOSAL

FIGURE B-17

THE HYGAS PROCESS - COMMERCIAL SCALE

(SOURCE: 54)

bituminous coal. Depending on the overall project, the HYGAS pilot plant must be operated for a certain period in FY 1979, for back-up in the detailed design of a demonstration plant.

The effect of process variables will be determined including temperature, steam/oxygen ratio, oxygen/carbon ratio, and reactants' residence time on conversion and yield in the hydrogasifier with the steam/oxygen system. Additional catalysts in the coal gas recycle methanator will be evaluated. Effluent treatment, water reuse, and construction materials will be evaluated.

A conceptual design of a commercial-scale plant to convert coal to pipeline-quality synthetic gas utilizing the HYGAS Process will be completed mid-FY 1978. The design will be used to evaluate the HYGAS process and determine the feasibility of proceeding with a demonstration plant design based upon this process to be completed by April 1979. (39)

SYNTHANE PROCESS DESCRIPTION (COMMERCIAL SCALE)

The Synthane process is designed for the conversion of bituminous and subbituminous coal and lignite into sulfur-free substitute natural gas (SNG). The process can be modified to use air instead of oxygen to produce a low-Btu gas.

In the process, coal is pulverized until 70 percent of it passes through 200-mesh screen and is sent to lock hoppers where the pressure is raised to 68 atm. Pretreatment of coal with oxygen and steam to destroy its caking properties is done in a fluidized bed at 800°F.

The gasifier operates at 40 atm between 1,400 and 1,800°F. The pretreated coal is carbonized and gasified in a fluidized bed by steam and oxygen. The cooling jacket in the gasifier walls produces steam. Char is removed from the bottom of the gasifier and from the cyclones in which the raw product gas is de-dusted. The char is burned to produce power to produce O_2 and to balance the system. Tar is separated by water scrubbing before the gas enters the shift reactors; there the H_2 to CO ratio is adjusted as needed for methanation.

Two methanation systems have been proposed: a tube wall reactor wherein the catalyst is sprayed onto cooled tube walls (the heat extracted is used to raise steam) and a hot-gas recycle methanator wherein the catalyst is sprayed onto uncooled metal plates.

The environmental control process consists of cyclone separators and bag filters to remove dust and char particles, and scrubbers to remove tar. A hot potassium carbonate solution removes CO_2, H_2S, and COS. The remaining traces of hydrogen sulfide and other sulfur compounds are reduced by passing the gas stream through iron oxide and char towers. Sulfur compounds are converted to elemental sulfur by treatment in a Stretford unit. Liquid waste streams such as leachate from coal storage, condensate streams from gasifier/ scrubber/ shift converter, and the regenerator are passed through strippers, a Phosam process, and biological treatment where ammonia is recovered, phenol is destroyed, process water is recycled, and solid residue is generated. (5)

Developer. ERDA, Pittsburgh Energy Research Center (PERC).

Status.

The Synthane process has been under development by the Bureau of Mines (BOM) at Pittsburgh Energy Research Center (PERC), Bruceton, Pennsylvania, since the early 1960s. A preliminary design contract was awarded to M. W. Kellogg Company in 1970, to determine whether there were sufficient data to design a 75-tons/day Synthane pilot plant, which was built by Rust Engineering in 1975. Lummus is now operating the pilot plant to acquire data to evaluate technical and operational feasibility of the process and to provide information required for scaleup.

The following areas are being investigated on pilot scale:

- Solids handling: lock hoppers for coal feed and char removal
- Gasification: hydrogasification in fluidized beds and a steam jacketed reactor
- Purification: hot potassium carbonate in packed towers with char and iron oxide towers
- Methanation catalytic reactor systems: 1) tube wall reactor (catalyst sprayed on inside of tubes), and 2) hot product-gas recycle catalyst.

Final construction was completed in the end of CY 1976. Nonagglomerating coals were tested in FY 1977. Tests on agglomerating coals began in late FY 1977 and will continue to the end of FY 1978. In early FY 1979, mechanical reliability tests are planned, after which time a decision to cease or extend operations will be made.

The pilot plant has been successfully operated on Rosebud subbituminous coal. The results showed that pipeline gas from such coals could be produced for approximately $3.50/million Btu. A feature of these pilot plant runs was demonstration that the environmental impact of the Synthane process could be minimized by adjustments to operating techniques. This resulted in a decrease in capital costs and an improvement in operating efficiency. Current operation is aimed at use of agglomerating, bituminous coals. (39)

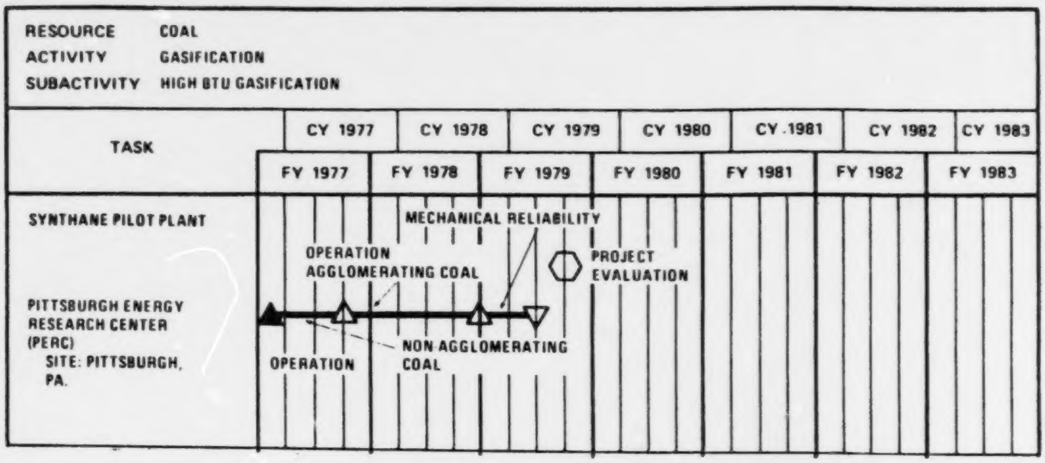


FIGURE B-18

SYNTHANE PROCESS PROJECT SCHEDULE

(SOURCE: 39, p. 114)

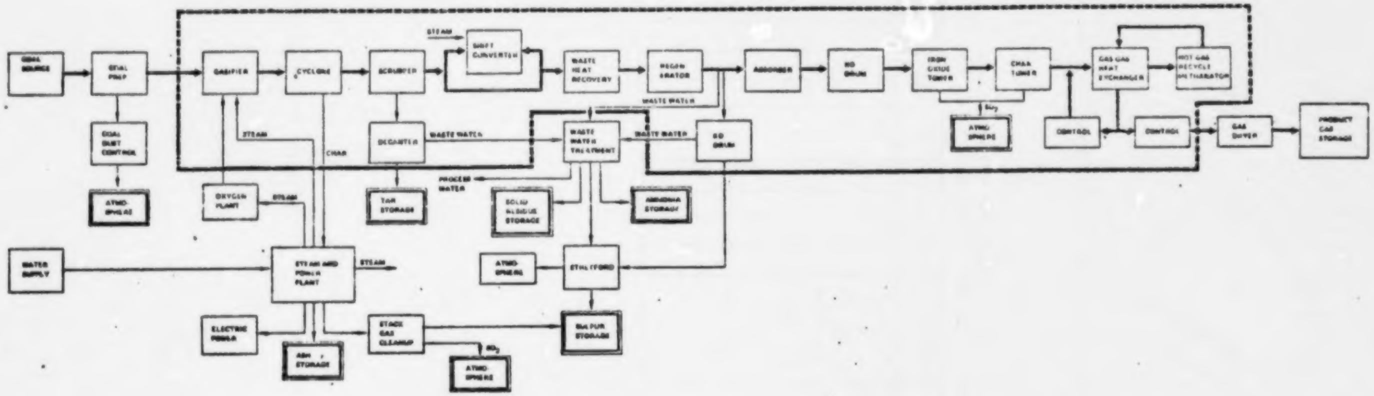

COAL SOURCE
COAL PREP
COAL DUST CONTROL
ATMOSPHERE
GASIFIER
CYCLONE
SCRUBBER
STEAM
SHIFT CONVERTER
WASTE HEAT RECOVERY
REGENERATOR
ABSORBER
KO DRUM
IRON OXIDE TOWER
CHAR TOWER
GAS GAS HEAT EXCHANGER
HOT GAS RECYCLE METHANATOR
ATMOSPHERE
CONTROL
CONTROL
GAS DRYER
PRODUCT GAS STORAGE
STEAM
CHAR
DECANTER
WASTE WATER
WASTE WATER
WASTE WATER TREATMENT
WASTE WATER
KO DRUM
OXYGEN PLANT
STEAM
TAR STORAGE
PROCESS WATER
SOLID RESIDUE STORAGE
AMMONIA STORAGE
WATER SUPPLY
STEAM AND POWER PLANT
STEAM
ATMOSPHERE
STRETFORD
ELECTRIC POWER
ASH STORAGE
STACK GAS CLEANUP
SO_2
ATMOSPHERE
SULFUR STORAGE

FIGURE B-19

THE SYNTHANE PROCESS - COMMERCIAL SCALE

(SOURCE: 64 and 54)

FIXED-BED, STRIRRED (MERC) PROCESS DESCRIPTION (PILOT PLANT SCALE)

This process will accept both caking and non-caking coals. Continuous stirring of the fuel bed is required to maintain gas quality and to prevent ash agglomeration. The amount of tar and oil produced is quite high.

The gasifier is equipped with three agitator arms and a rotating grate. The grate is composed of three flat circular plates, stacked eccentrically.

Unsized coal is fed into the top of the gasifier operating at 300 psi. The coal forms a bed on the grate. Air mixed with superheated steam is fed into the gasifier below the grate and flows upward through the descending coal, gasifying and partially burning it. The agitator arms are continuously rotated and moved vertically to provide complete mixing of the air, steam, and coal and to minimize ash and coal agglomeration. The grate supports the fuel bed and when it also rotates the ash drops to the bottom of the gasifier where it is withdrawn.

The pilot plant is designed to vent the product gas. This gas is withdrawn from the top of the gasifier. It passes through a cyclone and water scrubber to remove particulates and tar. A product-gas sidestream is fed into a turbine combustor section for corrosion/erosion test purposes.

The pilot plant facility also consists of a particulate removal section and a gas sampling section.

In commercial scale plant, the gas from the cyclone would be cooled to separate the tar and oil. The gas would then be sent to an acid gas removal unit and a low-Btu producer gas would result. Waste water treatment would be necessary. (5)

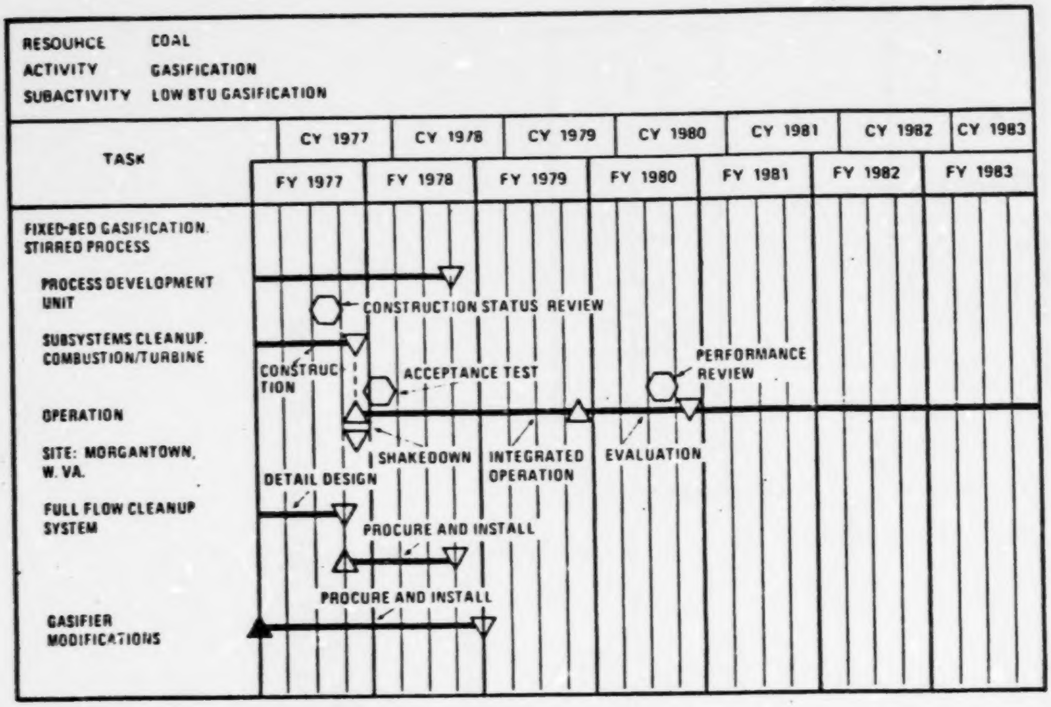
Developer. ERDA-MERC, Morgantown, WV.

Status.

The low-Btu gasification (moving fixed-bed) PDU has been operated at the Morgantown Energy Research Center (MERC) for several years. The system was modified in 1976 to provide improved methods for coal feeding, ash removal, stirring, lock hoppers, and data collection. The system is being fitted for use of oxygen as well as air.

A full flow system has been designed to clean producer gas of tars, particles, light oils, and alkali metals.

A variety of test programs, including novel gas cleanup systems, combustion and equipment improvement, are planned. Operation of the fully integrated process, including gasifier, cleanup, and combustion, will begin in late FY 1978. (39)



MILESTONE SYMBOLS ARE DEFINED ON LAST PAGE OF THIS DOCUMENT

FIGURE B-20

FIXED-BED, STIRRED GASIFIER PROJECT SCHEDULE

(SOURCE: 39, p. 125)

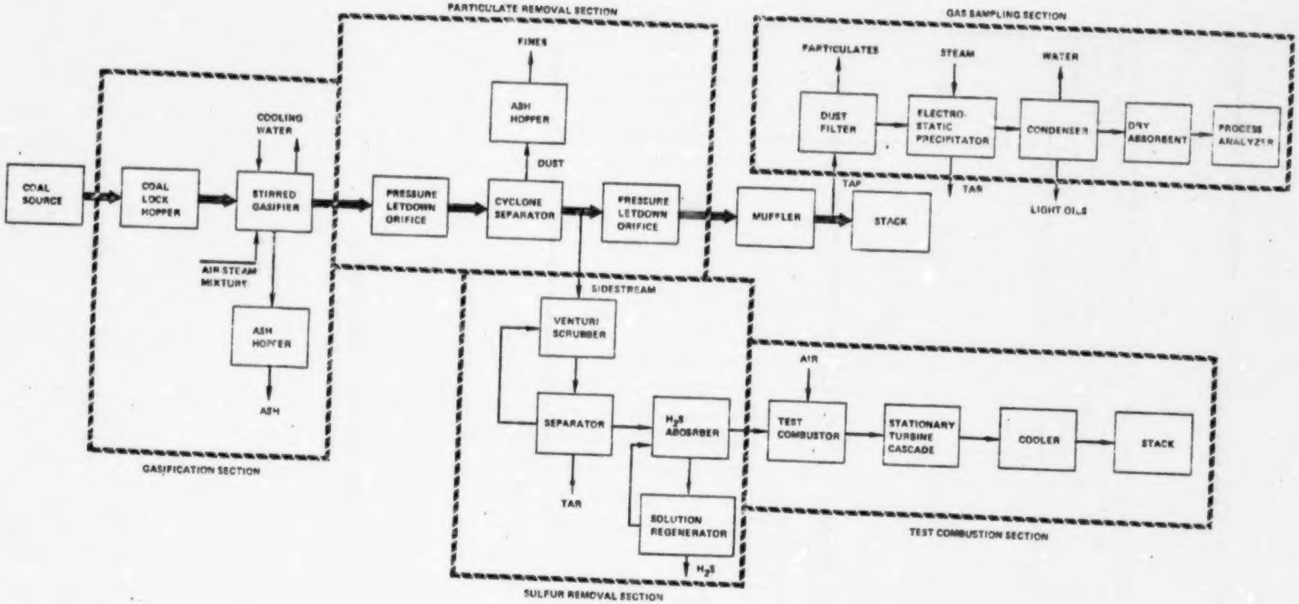

PARTICULATE REMOVAL SECTION
GAS SAMPLING SECTION
COAL SOURCE
COAL LOCK HOPPER
COOLING WATER
STIRRED GASIFIER
AIR STEAM MIXTURE
ASH HOPPER
ASH
GASIFICATION SECTION
PRESSURE LETDOWN ORIFICE
FINES
ASH HOPPER
DUST
CYCLONE SEPARATOR
PRESSURE LETDOWN ORIFICE
SIDESTREAM
MUFFLER
TAP
STACK
PARTICULATES
DUST FILTER
STEAM
ELECTRO-STATIC PRECIPITATOR
TAR
WATER
CONDENSER
LIGHT OILS
DRY ABSORBENT
PROCESS ANALYZER
VENTURI SCRUBBER
SEPARATOR
TAR
H_2S ABSORBER
SOLUTION REGENERATOR
H_2S
SULFUR REMOVAL SECTION
AIR
TEST COMBUSTOR
STATIONARY TURBINE CASCADE
COOLER
STACK
TEST COMBUSTION SECTION

FIGURE B-21

FIXED-BED, STIRRED GASIFIER PROCESS - PDU SCALE

(SOURCE: 47)

FIXED BED, SLAGGING PROCESS DESCRIPTION (PILOT PLANT SCALE)

This gasifier operates at a higher temperature than the conventional dry ash Lurgi so that the ash is removed as a molten slag. This also means that a revolving grate is not required. It is expected that the gasifier will operate with lignite without moisture content limitations and fines will be acceptable. By gasifying at high temperatures, steam requirements are reduced.

In this process, coal, periodically charged to the lock hopper, moves by gravity flow into the gas generator and is continuously gasified by an oxygen-steam mixture introduced through four water-cooled tuyeres at the bottom of the gasifier. Molten slag is formed at the hearth and flows through a central, one-inch diameter taphole into a water quench bath.

The product gas leaving the gasifier contains water vapor and tar. It is scrubbed in a spray cooler with condensed recycle liquor. The washed gas is then cooled to 60°F in an indirect cooler before being sampled, metered and flared. The gas liquor is periodically discharged from the spray cooler to a settling tank. Some cooled product gas is compressed and recycled through the coal lock to prevent steam and tar vapors from entering the coal lock and condensing on the incoming coal. Gas from the high temperature reaction zone can be drawn through the taphole to aid slag flow. This gas is cooled and metered in a separate circuit. The heating value of this gas is approximately 350 Btu/scf. (5)

Developer. ERDA-GFERC, Grand Forks, ND.

Status. A 25 tons per day PDU that was operated in the period 1958 to 1964 has been reconditioned. Reactivation occurred by mid-1976 and operation of the 25 tons per day, 1.6 x 10^4 SCFD output PDU will continue to the end of FY78. (39)

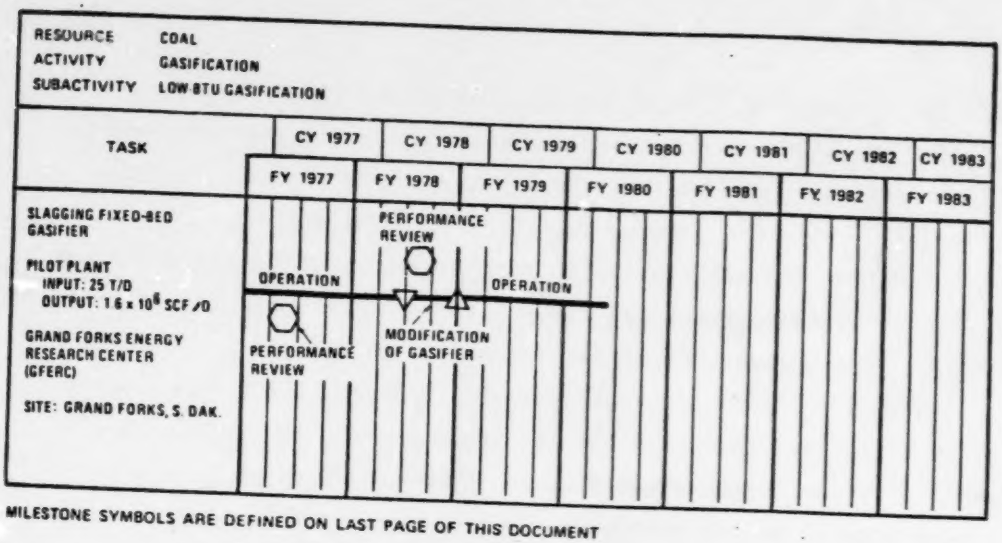


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FIGURE B-22

FIXED-BED GASIFIER, SLAGGING PROCESS PROJECT SCHEDULE
(SOURCE: 39, p. 127)

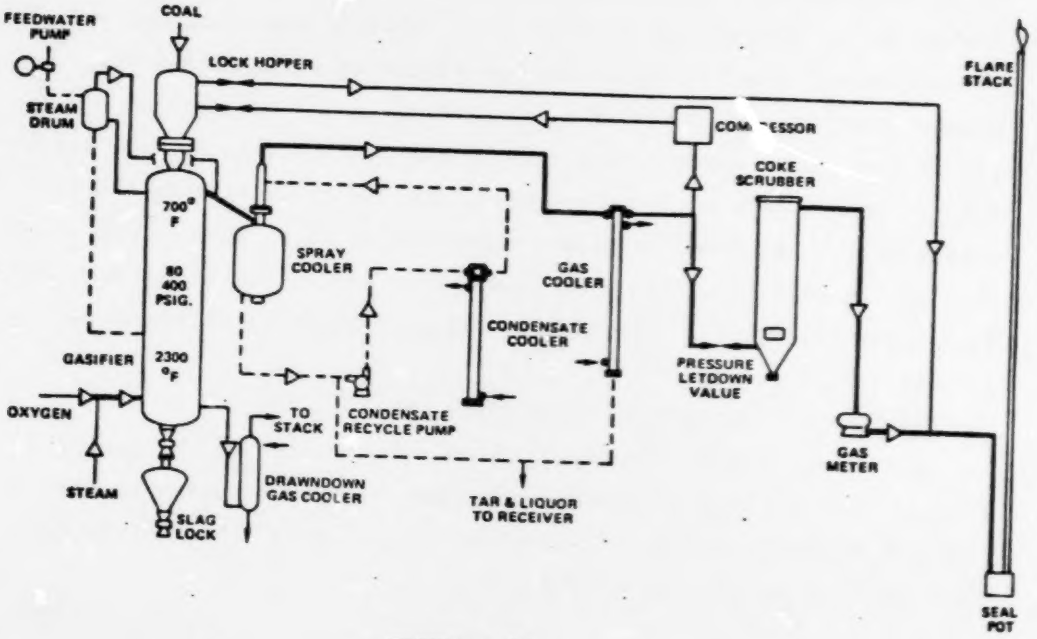

FEEDWATER PUMP
COAL
LOCK HOPPER
FLARE STACK
STEAM DRUM
COMPRESSOR
COKE SCRUBBER
700° F
80 400 PSIG.
SPRAY COOLER
GAS COOLER
CONDENSATE COOLER
PRESSURE LETDOWN VALUE
GASIFIER
2300 °F
OXYGEN
STEAM
TO STACK
CONDENSATE RECYCLE PUMP
GAS METER
DRAWNDOWN GAS COOLER
TAR & LIQUOR TO RECEIVER
SLAG LOCK
SEAL POT

FIGURE B-23

FIXED-BED GASIFIER, SLAGGING PROCESS - PILOT SCALE
(SOURCE: 39, p. 126)

FLUIDIZED BED, TWO STAGE PRESSURIZED GASIFICATION PROCESS DESCRIPTION

The process relies upon crushed feed coal (.125" x. 25") but will accept a variety of coals including caking coals and those with high ash content.

The process consists of three fluidized beds: a fluidized bed dryer, a pressurized fluid bed devolatilizer-desulfurizer and a fluidized bed gasifier-combustor.

Crushed coal is dried with recycled fuel gas and then transported to the devolatilizer-desulfurizer unit. The recirculating fluidized bed of this unit devolatilizes, desulfurizes and partially hydrogasifies the coal. Dried coal is introduced through a central draft tube where the coal, char, and sorbent are carried upward by gases flowing from the gasifier. The recycle solids, descending in the annular downcomer, are needed to dilute the feed coal and to temper the hot inlet gases. The prevention or controlled agglomeration of the coal as it devolatilizes and passes through its plastic phase is effected by maintaining a large ratio (up to 100:1) of recycle solids to coal feed rate. A dense dry char is withdrawn at the top of the draft tube. Dolomite or CaO is added to this bed to remove the H_2S produced. Spent sorbent is withdrawn from the reactor after char removal and is regenerated. Most of the heat required for this unit is supplied by the high temperature gas from the gasifier. Product gas is stripped of fines and ash, cooled, and then scrubbed with water. The resulting clean fuel gas can then be forwarded to the gas turbine combustor section of a combined cycle power plant, for which use the process is oriented.

Final gasification is conducted in a fluidized bed at 1,800 to 2,000°F. Char from the devolatilizer-desulfurizer and fines removed from the product gas are burned with air in the lower leg for removal. Gasification occurs in the upper bed; this hot CO and H_2 rich stream is fed to the devolatizer-desulfurizer to provide the basic heat source for the process. (5)

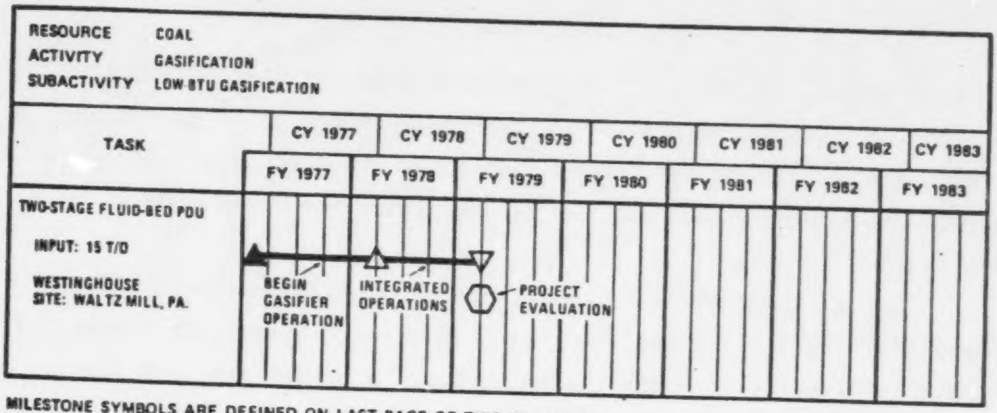
Developer. Westinghouse Electric Corporation in partnership with Public Service of Indiana, Bechtel, Amax Coal Co. and Peabody/ Kennecott.

Status.

Initial development of the concept involved laboratory research and the design and construction of a process development unit with a coal feed design capacity of 1,200 lb/hr. The PDU and its auxilliary subsystems were completed at the Westinghouse laboratory in Waltz Mill, Pennsylvania, in 1975. A test program was then initiated to establish the operating characteristics of the gasification system and to provide data for developing scaleup factors for a pilot plant.

During FY 1977, operating tests of the gasifier-combustor were conducted with a variety of feed chars and conditions. Tests were also successfully run feeding coal directly to the gasifier-combustor. These tests demonstrated that this subsystem can gasify various feedstocks and generate a gas satisfactory for operation of the first stage of the process, i.e., the devolatilizer. The chars tested included coke breeze, COED char made from both western Kentucky and Utah coals, and PDU char made in the devolatizer from the Pittsburgh seam coals.

During CY 1978, the complete coal gasification system will be operated in an integrated manner with both the devolatilizer, the gasifier, and all associated equipment. Test data will be obtained to determine process performance and to enable process economics calculating and scaleup of the process. A detailed analysis of the operational test data is scheduled for the end of FY 1978. By the end of CY 1978, a decision will be made on the need for further development of the process concept at a pilot plant scale. (39)



RESOURCE COAL
ACTIVITY GASIFICATION
SUBACTIVITY LOW-BTU GASIFICATION

TASK	CY 1977	CY 1978	CY 1979	CY 1980	CY 1981	CY 1982	CY 1983
	FY 1977	FY 1978	FY 1979	FY 1980	FY 1981	FY 1982	FY 1983
TWO-STAGE FLUID-BED PDU INPUT: 15 T/D WESTINGHOUSE SITE: WALTZ MILL, PA.	BEGIN GASIFIER OPERATION	INTEGRATED OPERATIONS	PROJECT EVALUATION				

MILESTONE SYMBOLS ARE DEFINED ON LAST PAGE OF THIS DOCUMENT
NOTE: BUDGET DETAILS ARE PROVIDED IN SECTION 6.0.

FIGURE B-24
FLUIDIZED-BED GASIFICATION, TWO-STAGE PRESSURIZED PROJECT SCHEDULE
(SOURCE: 39, p. 129)

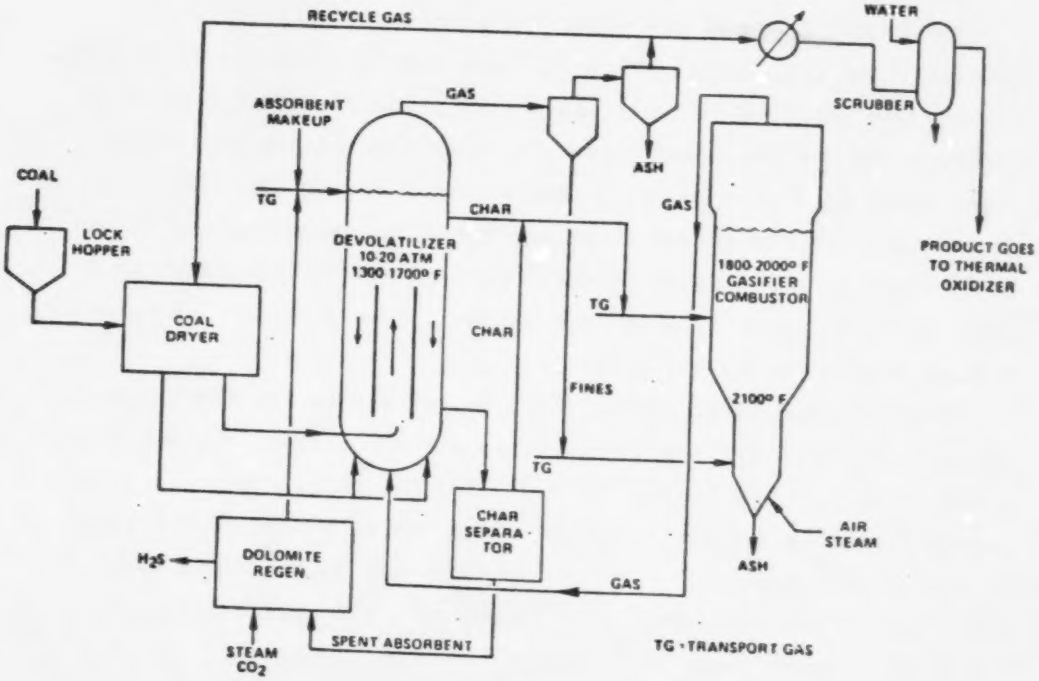

RECYCLE GAS
WATER
SCRUBBER
GAS
ABSORBENT MAKEUP
ASH
COAL
LOCK HOPPER
TG
CHAR
GAS
DEVOLATILIZER 10-20 ATM 1300-1700° F
1800-2000° F GASIFIER COMBUSTOR
PRODUCT GOES TO THERMAL OXIDIZER
COAL DRYER
TG
CHAR
FINES
2100° F
TG
CHAR SEPARATOR
AIR STEAM
H_2S
DOLOMITE REGEN
GAS
ASH
STEAM CO_2
SPENT ABSORBENT
TG - TRANSPORT GAS

FIGURE B-25
FLUIDIZED-BED GASIFICATION, TWO-STAGE PRESSURIZED PROJECT SCHEDULE
(SOURCE: 39, p. 128)

FLUIDIZED-BED, THREE-STAGE PROCESS DESCRIPTION (COMMERCIAL SCALE)

The goal of the multiple fluidized-bed process is to gasify both caking and non-caking coals and produce low-Btu fuel gas. After desulfurization the fuel gas can be used in conventional power systems.

The three-stage process consists of three fluidized bed reactors in series. Pulverized coal is stored in a pressurized lock hopper; it is fed into the first-stage reactor through a rotary air lock feeder. This stage functions as a pre-treatment step, devolatizing the fresh coal feed with the hot off gas from the third-stage reactor. The coal flows by gravity from the first stage to the lower part of the second-stage reactor bed. The first-stage off gas, containing entrained volatiles, enters the second stage below the gas distributor.

The second stage is the major gasification stage. Here the devolatilized coal and the tars and oils entrained in the first-stage off gas are gasified with air mixed with steam or carbon dioxide to generate the desired product gas. Product gas exiting the second stage flows to a cyclone which removes entrained solids. These solids are returned to the second-stage reactor. Any remaining char fines are removed in a bag-house filter. Product gas is then taken to a scrubber-cooler, and finally to a sulfur recovery unit. The resulting cleaned cooled gas is a low-Btu fuel gas.

Char from the second stage flows by gravity to the third stage where it is fluidized and combusted by air and steam. The ash formed flows to an ash lock hopper for removal. The third-stage flue gas passes through a cyclone where entrained ash is removed and returned to the third-stage bed. Flue gas is then sent to the first stage to continue the process. Neither oils nor tars are produced during three-stage operations.

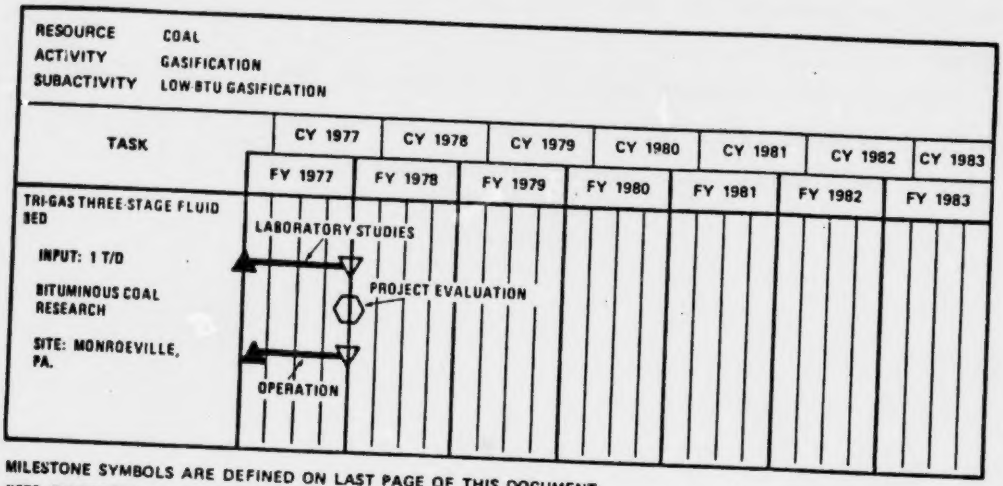
Product gas heating value requirements dictate the operating conditions as well as the gasifying medium in the second stage. Air and steam gasification yield a low-Btu fuel gas while oxygen and steam yield a medium-Btu gas. (5)

Developer. Bituminous Coal Research (BCR), an affiliate of the National Coal Association.

Status. A one ton per day PDU is currently operating in Monroeville, PA.

Testing of a caking coal (Illinois No. 6) in Stage 1 began in mid-1976. A series of tests at low temperatures (between 800°F and 900°F) demonstrated the ability to produce a noncaking product char in Stage 1.

The current contract expired on October 20, 1977. A new contract will be awarded in FY 1978 to allow for reactor modifications, additional lab studies, and integrated operation of the unit. (39)



MILESTONE SYMBOLS ARE DEFINED ON LAST PAGE OF THIS DOCUMENT

NOTE: BUDGET DETAILS ARE PROVIDED IN SECTION 6.0.

FIGURE B-26

FLUIDIZED-BED, THREE STAGE PRESSURIZED PROJECT SCHEDULE

(SOURCE: 39, p. 131)

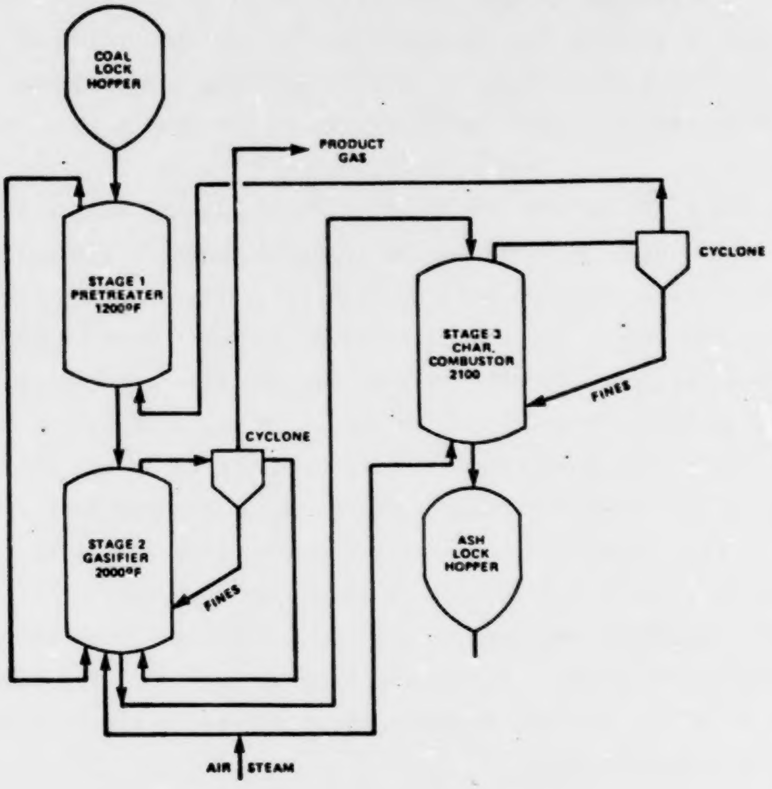

COAL LOCK HOPPER
PRODUCT GAS
STAGE 1 PRETREATER 1200°F
CYCLONE
STAGE 3 CHAR. COMBUSTOR 2100
FINES
CYCLONE
STAGE 2 GASIFIER 2000°F
FINES
ASH LOCK HOPPER
AIR
STEAM

FIGURE B-27

FLUIDIZED-BED GASIFICATION, THREE STAGE PRESSURIZED PROCESS - PDU SCALE

(SOURCE: 39, p. 130)

IN SITU GASIFICATION TECHNOLOGY OPTIONS

Linked Vertical Wells Process

The LVW process is applied by drilling vertical wells into the coal seam to provide for injection of air and collection of product gases. Reverse combustion is used to link the wells through the coal seam, followed by forward gasification of the coal between the linked wells.

In Figure B-28, the center and right wells are linked by reverse combustion. High pressure air is injected in the right well and flows to the center production well through naturally occuring cracks and paths in the coal. The combustion zone advances from center well to right well (injection well) against the gas flow creating a hot char channel between the wells. Once two wells are linked, the gasification front reverses direction moving with the gas flow. This second stage, called forward gasification, is shown between left and center wells in the diagram. Forward gasification proceeds along the linked passage which widens and caves in to expose more coal. (38)

This system is designed to produce low-Btu gas from western subbituminous coal seams. It has the highest potential for commercialization by 1985. Project schedule is presented in Figure B-29.

Packed Bed-Gasification

As illustrated in Figure B-30, this process uses chemical explosives to fracture the coal deposit creating a permeable zone. The coal in a permeable fractured bed has a large surface area which increases contact between the coal and the gaseous reactants. Collection wells are drilled to the bottom of the fractured zone along its perimeter; injection wells are drilled to the top of the zone. Gasificatiodn with steam and oxygen begins at the top of the fractured zone and moves downward and outward. The liquid products drain downward through the bed where they are removed through production wells. This reduces liquid plugging and gas override. As the coal is gasified, fractured coal falls into open channels and prevents short circuiting between the injection and production wells. (38)

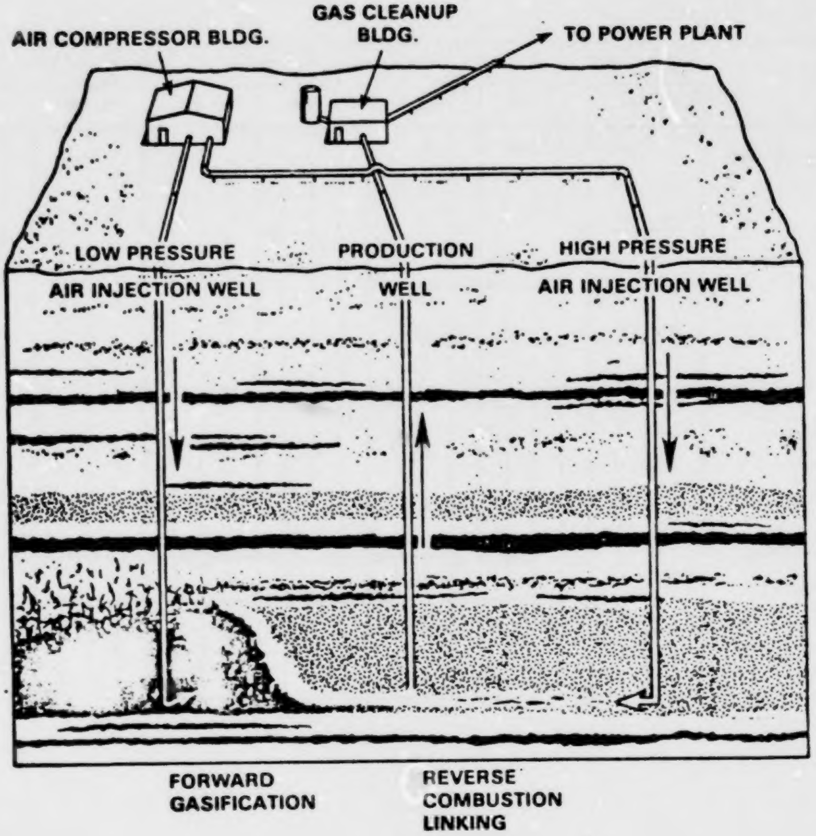

AIR COMPRESSOR BLDG.
GAS CLEANUP BLDG.
TO POWER PLANT
LOW PRESSURE AIR INJECTION WELL
PRODUCTION WELL
HIGH PRESSURE AIR INJECTION WELL
FORWARD GASIFICATION
REVERSE COMBUSTION LINKING

FIGURE B-28

LINKED VERTICAL WELLS PROCESS

(SOURCE: 39, p. 162)

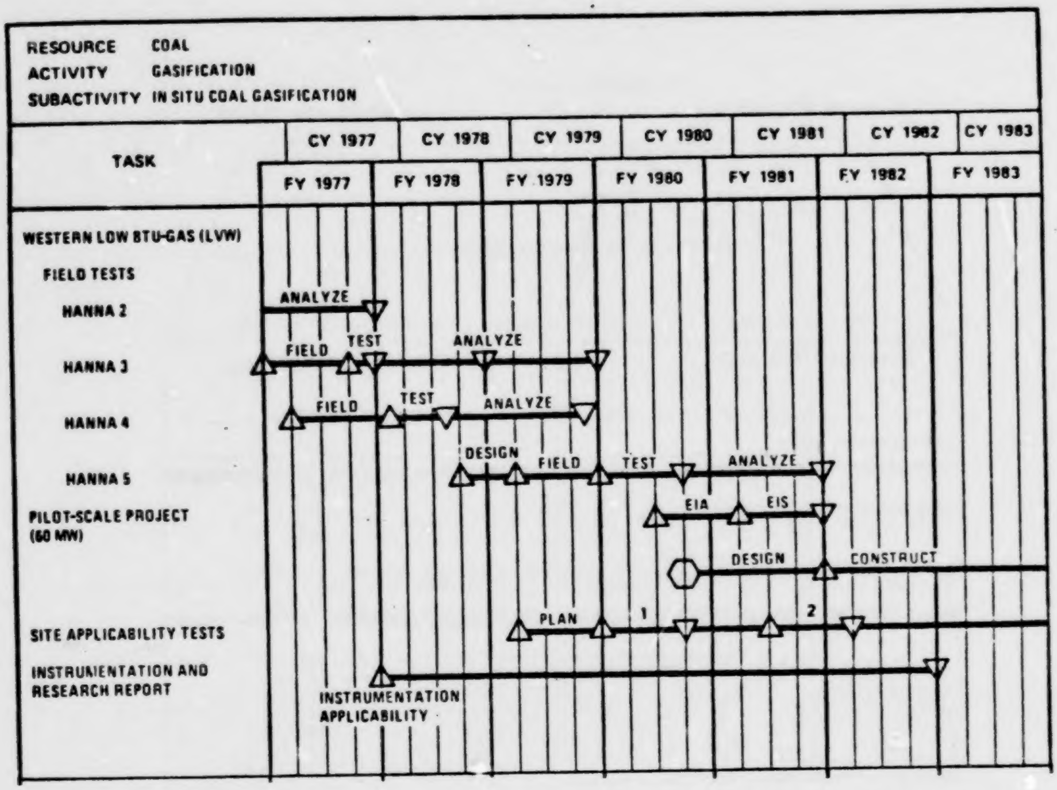


FIGURE B-29

LINKED VERTICAL WELLS PROJECT SCHEDULE

(SOURCE: 39, p. 164)

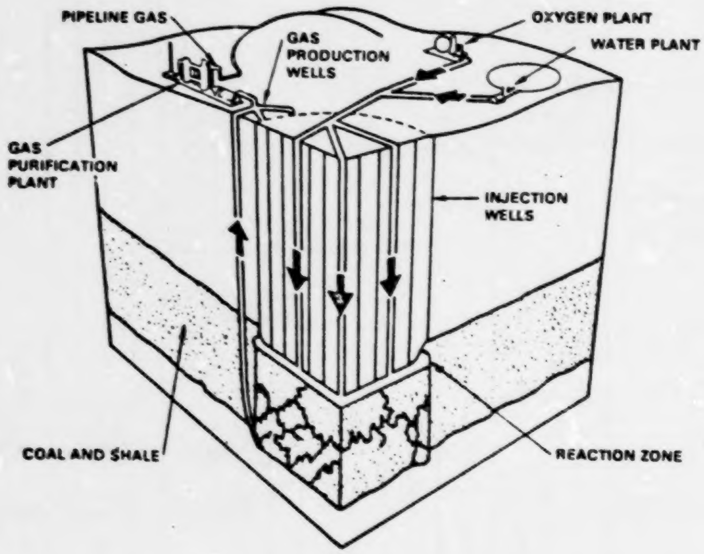

PIPELINE GAS
GAS PRODUCTION WELLS
OXYGEN PLANT
WATER PLANT
GAS PURIFICATION PLANT
INJECTION WELLS
COAL AND SHALE
REACTION ZONE

FIGURE B-30
PACKED-BED PROCESS

(SOURCE: 39, p. 165)

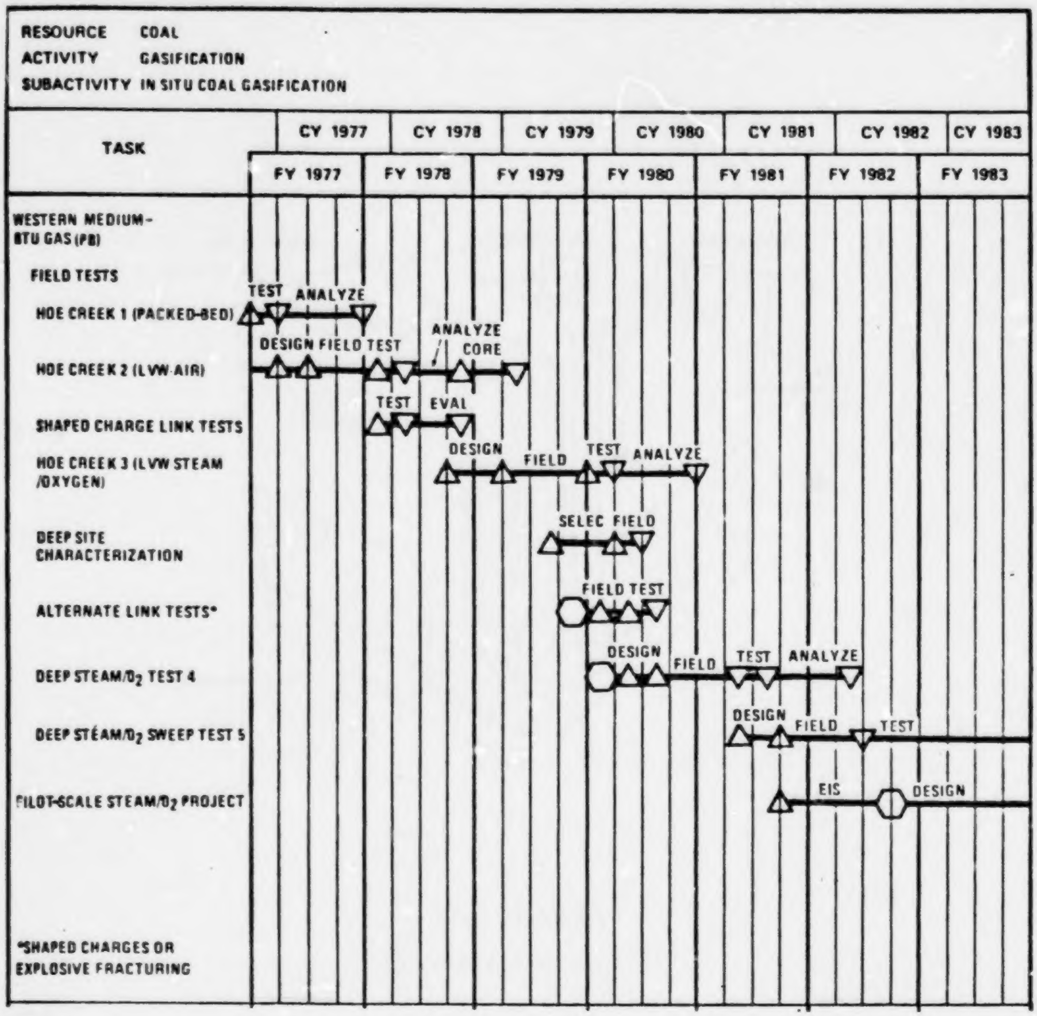


FIGURE B-31

PACKED-BED PROJECT SCHEDULE

(SOURCE: 39, p. 167)

The packed bed process is designed to produce medium-Btu gas from western subbituminous coal seams. Figure B-31 present project schedules.

Eastern Coal Technology (Longwall Generator)

The LG process uses directionally drilled holes aligned perpendicular to the orientation of the major fracture system to provide the maximum coal surface for the gasification reaction. Deep seams of bituminous coal 5 to 15 feet thick will be gasified with air to produce low-Btu gas for power generation or industrial use. Deviated wells are drilled from the surface and curved to produce long boreholes lying in rows within the coal seam. The coal is burned between the parallel rows of horizontal holes that serve as the injection and production wells. The product gases flow through the coal in the direction of maximum permeability, eventually reaching the production wells. This may eliminate the need to fracture the coal. The process is illustrated in Figure B-32.

This process may be applicable to thin, low-permeability, high-swelling eastern coal seams which are the most difficult to gasify by underground methods. The project schedule is presented in Figure B-33. (38)

Steeply Dipping Beds Process

This process is being developed to gasify coal seams that dip at angles greater than about 35°. This coal is not recoverable by existing mining methods. Drilling requirements and subsidence problems are less for the SDB process than for the other in situ gasification processes.

As illustrated in Figure B-34, slanted holes, cased only through the overburden, are drilled into and through the coal bed following the dip. A channel connects the lower ends of these slanted production wells. All injections wells are drilled either vertically, slanted underneath the coal bed, or in the coal bed itself to intersect the horizontal channel connecting the uncased production holes. Product gases are withdrawn through the slanted holes in the coal bed midway between the injection holes. Reducing reactions occur on the surface of the slanted, uncased exhaust holes. As the coal above and along the horizontal channel burns away, the fire zone advances updip. The schedule is presented din Figure B-35.

Over 100 billions tons of SDB coal are estimated to exist in the United States. A large percentage of the Pacific coast coal is steeply dipping so commercialization of an SDB process could contribute to the future energy supply of the populous west coast. There are also substantial SDB deposits in the Rocky Mountain area and lesser amounts in the Appalachian and Interior coal regions. (38)

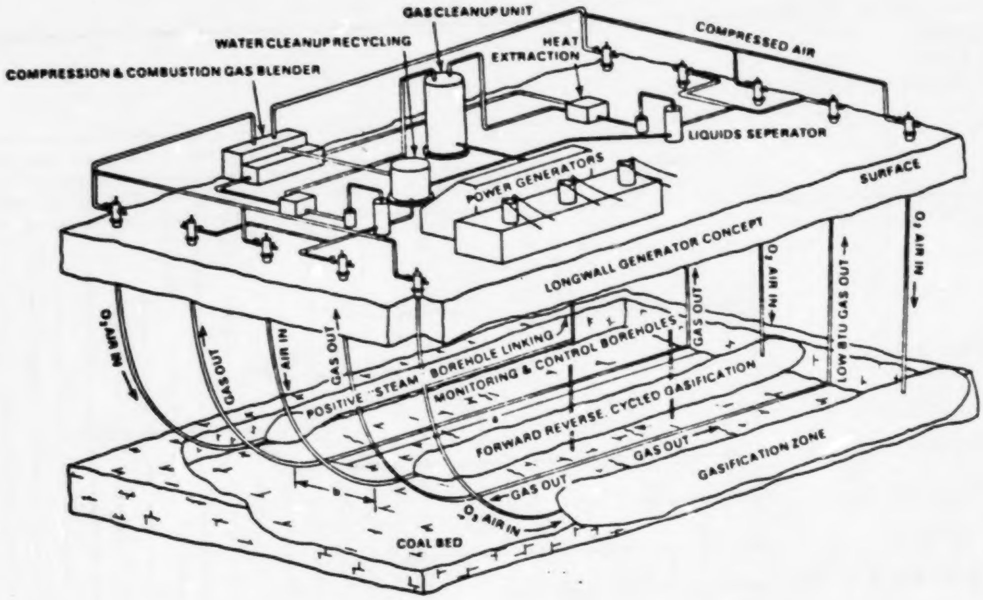

GAS CLEANUP UNIT
WATER CLEANUP RECYCLING
COMPRESSION & COMBUSTION GAS BLENDER
HEAT EXTRACTION
COMPRESSED AIR
LIQUIDS SEPERATOR
POWER GENERATORS
SURFACE
LONGWALL GENERATOR CONCEPT
O2 AIR IN
GAS OUT
AIR IN
GAS OUT
GAS OUT
O2 AIR IN
LOW BTU GAS OUT
O2 AIR IN
POSITIVE "STEAM" BOREHOLE LINKING
MONITORING & CONTROL BOREHOLES
FORWARD REVERSE. CYCLED GASIFICATION
GAS OUT
GASIFICATION ZONE
GAS OUT
O2 AIR IN
COAL BED

FIGURE B-32

LONGWALL GENERATOR PROCESS

(SOURCE: 39, p. 168)

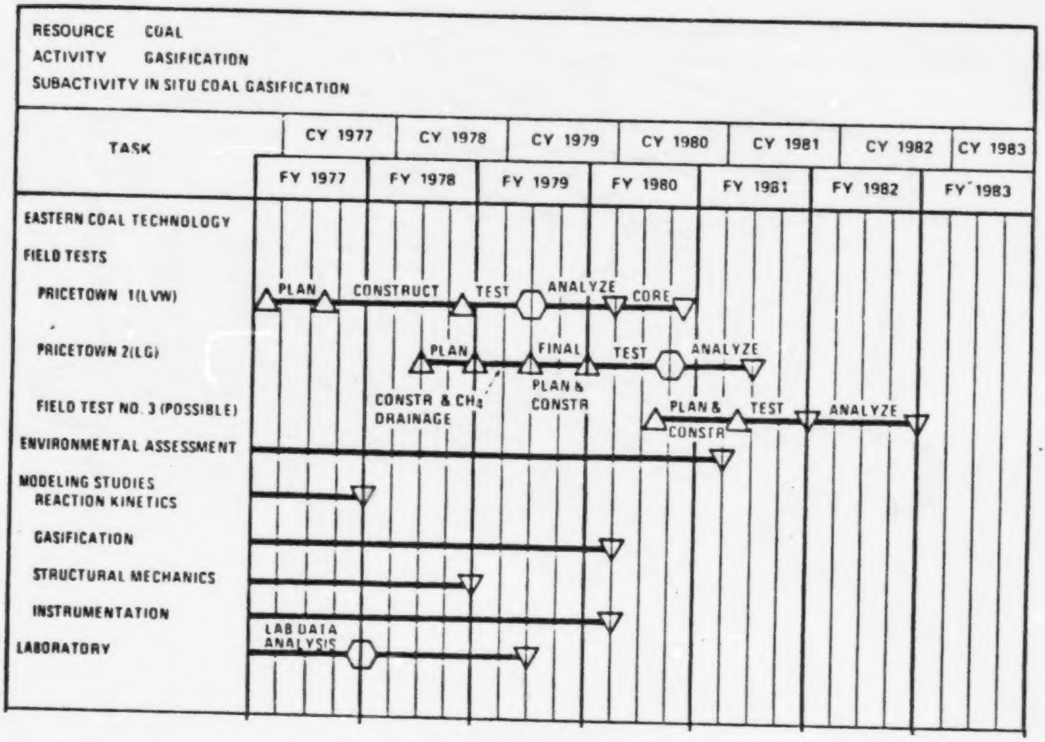


FIGURE B-33

LONGWALL GENERATOR PROJECT SCHEDULE

(SOURCE: 39, p. 169)

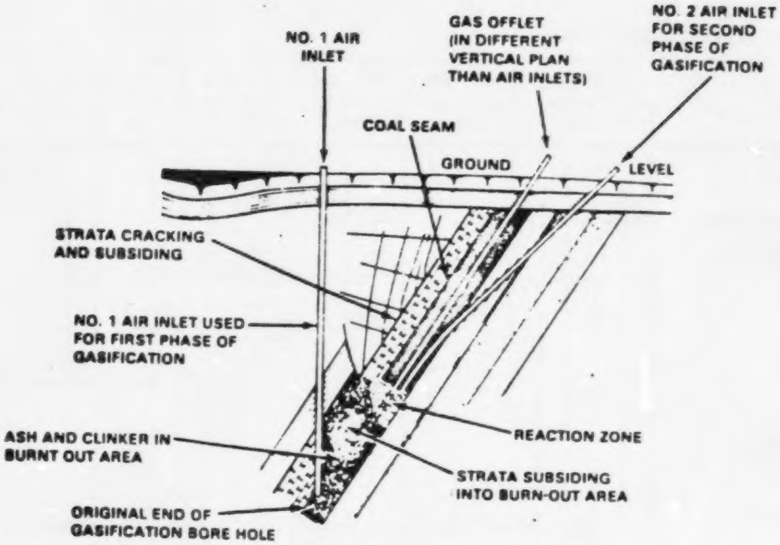

NO. 1 AIR INLET
GAS OFFLET (IN DIFFERENT VERTICAL PLAN THAN AIR INLETS)
NO. 2 AIR INLET FOR SECOND PHASE OF GASIFICATION
COAL SEAM
GROUND
LEVEL
STRATA CRACKING AND SUBSIDING
NO. 1 AIR INLET USED FOR FIRST PHASE OF GASIFICATION
REACTION ZONE
ASH AND CLINKER IN BURNT OUT AREA
STRATA SUBSIDING INTO BURN-OUT AREA
ORIGINAL END OF GASIFICATION BORE HOLE

FIGURE B-34

STEEPLY DIPPING BED CONCEPT

(SOURCE: 39, p. 170)

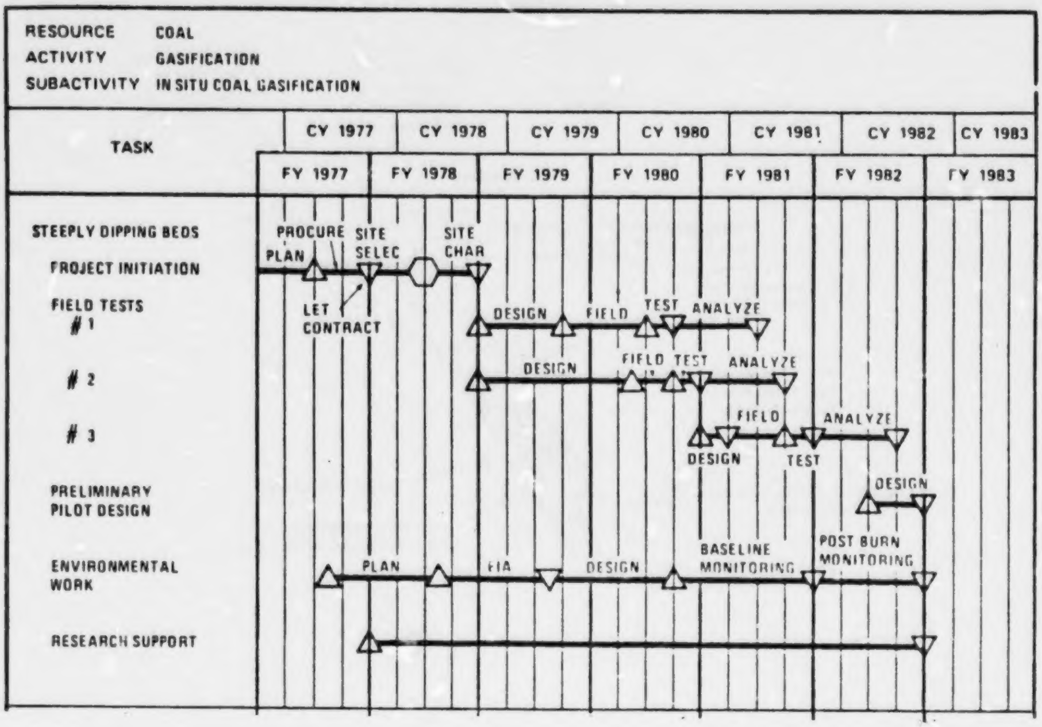


FIGURE B-35

STEEPLY DIPPING BED PROJECT SCHEDULE

(SOURCE: 39, p. 172)

APPENDIX C

POTENTIAL POLLUTANTS OF CONCERN

Organic compounds identified in effluents
Elemental compounds identified in effluents
Some environmentally hazardous organic species
Possible constituents of gasifer off gas by boiling range
Tar acids from low temperature bituminous tar
Tar bases from low-temperatures bituminous tar
Catalysts and chemicals used in liquefaction
High-Btu gasification inputs other than coal
Organic acids in in situ product water
Composition of in-situ produced gas

TABLE C-1

ORGANIC COMPOUNDS IDENTIFIED IN EFFLUENTS FROM ENERGY-RELATED PROCESSES

	Source of Liquid and Solid Effluents[a]					
Compound of Chemical Class	Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
Acenaphthalene						L
Acenaphthene		S				L
Acenaphthenols		S				
Acetophenone						L
Acetaldehyde			L		L	
Acetic acid			L			L
Aldehydes						L,S
Alkyl and aromatic hydrocarbons						L,S
Alkyl and aromatic amines					L	
Alkyl and aromatic alcohols						L
Aniline		L,S				
Anthraquinone/Disulfonic acid		L				
Anthracene					S	L
Benzaldehyde		L				
Benzoic acid						L
Benzene		L,S	L		L,S	L
Benzofuranol		L				

[a] L = Liquid effluents; S = Solid effluents
(SOURCE: 99, p. 12-20)

TABLE C-1 (CONT'D)

Compound of Chemical Class	Source of Liquid and Solid Effluents[a]					
	Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
Benzo(a)anthracene					S	
Benzo(a)anthracene, 7,12-dimethyl	X					
Benzonaphthiothiophenes		S				
Benzonitrile		L				
Benzo(a)pyrene	S				S	
Benzo(e)pyrene					S	
Benzo(g)chrysene					S	
Benzo(g,h,i)perylene	X				S	
Benzo(c)chrysene					S	
Biphenyl					S	
1-Butanol						L
2-Butoxyethanol						L
Carbon disulfide						L
Carbonyl sulfide						L
Carbazoles						L
m-Cresol		L	L		L	L
o-Cresol		L	L		L	L

TABLE C-1 (CONT'D)

Compound of Chemical Class	Source of Liquid and Solid Effluents[a]					
	Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
p-Cresol		L	L		L	L
Crysene					S	
Cresylic acid						L
1-Decanol						L
Diacetone alcohol						L
Dibenzofuran		S				L
Dibenzothiophenes		S				
Dibenz(a,h)anthracene					S	
Dibenz(a,j)acridine					S	
Dibenzo(cd, lm)perylene					S	
Dimethyl furan isomer						L
2,6-Dimethylnaphthalene						L
3,3-Diphenylpropanol						L
Dimethylphenol						L
Dodeane						L
Eicosane						L

TABLE C-1 (CONT'D)

Compound of Chemical Class	Source of Liquid and Solid Effluents[a]					
	Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
Ethylene glycol		L				
Ethyl naphthalene						L
o-Ethyltoluene						L
Fluorene		S			S	
Formaldehyde			L		L	
Fluoranthrene	X				S	
Furans					L	
Formic acid						L
Heneicosane						L
Heptadecane						L
Hexadecane						L
1-Hexanol						L
Indane		S				L
Indanols		S				
4-Indanol		S				
Indene		S				L

TABLE C-1 (CONT'D)

Compound of Chemical Class	Source of Liquid and Solid Effluents[a] Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
Indole		S				
Maleic anhydride						L
Maleic acid						L
m-Methoxyindole		S				
α-Methylbenzyl alcohol						L
Methyl biphenyl isomer						L
Methyl ethyl naphthalene isomer						L
1-Methyl indene						L
3-Methyl indene						L
1-Methylnaphthalene						L
2-Methylnaphthalene						L
Methyl indole		L				
Methyl mercaptan		L,S				L,S
Methyl anilines					L	
o-Methylstyrene						L
β-Methylstyrene						L

TABLE C-1 (CONT'D)

Compound of Chemical Class	Source of Liquid and Solid Effluents[a]					
	Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
Naphthalene		L,S	L			L
Naphthols		S				
1-Naphthol		L				
2-Naphthol		S				
Naphthol, methyl		L				
Nonadecane						L
1-Octanol						L
Octadecane						L
Oleic acid						L
Phenanthrene		L				
Phenanthrols		S				
Phenol		L,S	L		L,S	L
o-Ethylphenol		L				
p-Ethylphenol		L				
o-Isopropylphenol		L				
2-Methyl-4-ethylphenol		L				

TABLE C-1 (CONT'D)

	Source of Liquid and Solid Effluents[a]					
Compound of Chemical Class	Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
3-Methyl-6-ethylphenol		L				
4-Methyl-2-ethylphenol		L				
2,3,5-Trimethylphenol		L				
1-Phenylnaphthalene		S				
Pyridine		L,S			L	L
Pyridine, ethyl		L				
Pyridine, methyl		L				
Pyrroles						L
Pyrene	X				S	
Pyrocatechol		L,S				
Pyrocatechol, methyl		L				
Palmitic acid						L
Pentadecane						L
Quinolines						L
Styrene						L
Thiophene		L,S	L		L	L

TABLE C-1 (CONT'D)

Compound of Chemical Class	Source of Liquid and Solid Effluents[a]					
	Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
Thiophene, dimethyl		L,S				
Thiophene, methyl		L,S	L			
Toluene		L,S	L		L	L
Thiosulfide						L
α-Terpineol						L
Tetradecane						L
n-Tridecane						L
Undecane						L
Xylene (o,m,p)			L		L	L
2,3-Xylenol		L				
2,4-Xylenol		L				
2,5-Xylenol		L				
2,6-Xylenol		L				
3,4-Xylenol		L				
3,5-Xylenol		L				
γ-valerolactones	L					

TABLE C-1 (CONCLUDED)

Compound of Chemical Class	Source of Liquid and Solid Effluents[a]					
	Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
Sulfides						L,S
Sulfites						L,S
Sulfonates						L,S
Sulfones						L,S

TABLE C-2

ELEMENTAL COMPOUNDS IDENTIFIED IN EFFLUENTS
FROM ENERGY-RELATED PROCESSES

Elemental or Inorganics	Source of Liquid and Solid Effluents[a]					
	Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
Au				L,S	S	
Ag				L,S	S	
Al	L,S	L		L,S	S	
Al_2O_3	X	S		L,S	S	
Ammonia		L	L			
Ammonium cyanate			L			
As	S	L,S		L,S	L,S	
Arsenic acid, Na salt		L	L			
Ar_2O_2		L	L			
Arsine		L				
Ba	L,S	L	L	L,S	L,S	L
$BaCl_2$			L			
Be	S	L,S		L,S	S	
Bi				L,S	S	
B		L,S		L,S	S	

[a] L = Liquid effluents; S = Solid effluents

(SOURCE: 99, p. 21-26)

TABLE C-2 (CONT'D)

Elemental or Inorganics	Source of Liquid and Solid Effluents.[a] Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
BO		S				
Br_2		L			S	
Ca	S	L	S	L,S		
$CaCl_2$			L,S			
CaO		L			S	
$CaSO_4$			L,S			
CaS		S				
Cd	L,S	L,S	L	L,S	L,S	
$CdCl_2$			L			
$CdNO_3$			L			
Ce	S			L,S	S	
Cs				L,S	S	
CS_2		L,S				
COS		L	L			
Cl_2		L		L,S	S	

TABLE C-2 (CONT'D)

Elemental or Inorganics	Source of Liquid and Solid Effluents[a]					
	Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
Cr	L,S	L,S	S	L,S	S	
Co	S	L		L,S	S	S
Cobalt Molybdate			S			
Cu	L,S	L		L,S	S	L,S
Cyanides		L	L			
Dysorium	S			L,S	S	
Erbuim				L,S	S	
Europuin	S			L,S	S	
Fe	L,S	L		L,S		
$FeCl_3$	L	S				
F		L	L	L,S	S	
Ge		L		L,S	S	
Gadolinium				L,S	S	
Ga	S			L,S	S	
Hafnium	S			L,S	S	
Holmiun				L,S		

TABLE C-2 (CONT'D)

	Source of Liquid and Solid Effluents[a]					
Elemental or Inorganics	Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
HCl		L				
HCN		L,S	L			
HF		L				
H_2S		L	L			
Hg	S	L,S	L	L,S	L,S	
K	L,S	L			S	
La	S				S	
Li	S				S	
Mg	S	L			S	
$MgCl_2$			L,S	L,S		
MgO	X	L				
Mn	L,S	L		L,S	S	
Mo				L,S	S	S
Na	S	L,S	L,S	L,S	S	S
Nb						
Ni	L	S		L,S	S	L,S

TABLE C-2 (CONT'D)

	Source of Liquid and Solid Effluents[a]					
Elemental or Inorganics	Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
NiCO		L			L	
P	S	L			L,S	
Pb	L,S	L,S	L	L,S	S	
Rb	S					
Sa	S					
Sb	S	L,S	L	L,S	S	
Sc	S				S	
Se		L,S	L	L,S	L,S	
Sn		L			S	
Sr	S	L			S	L
Te		L			S	
Th	S					
Ti	S			L,S	S	
Tl	S					
U	S				S	
V	S	L,S	L	L,S	S	L,S

TABLE C-2 (CONCLUDED)

Elemental or Inorganics	Source of Liquid and Solid Effluents[a] Oil-Shale Processing	Coal Gasification	Coal Liquefaction	Coal-Fired Power-Plants	Coal Processing	Oil Refineries
V_2O_5		L	L,S			
Y					S	
Zn	L,S	L,S	L	L,S	S	L,S
ZnO		S			S	
Zr					S	

[a] L = liquid, S = solid effluents

TABLE C-3

SOME ENVIRONMENTALLY HAZARDOUS ORGANIC SPECIES

Compound	Hazard	Compound	Hazard
Polycyclic aromatics		Benzophenanthrenes	
		Benzo[*c*]phenanthrene	Carcinogen
Naphthalenes		2-Methylbenzo[*c*]phenanthrene	Suspected carcinogen
Naphtalene	Suspected carcinogen	Benzofluoranthenes	
1-Methyl naphthalene	Toxic	Benzo[*j*]fluoranthene	Carcinogen
		Benzo[*b*]fluoranthene	Carcinogen
Acenaphthenes		Benzo[*k*]fluoranthene	Suspected carcinogen
Acenaphtene	Suspected carcinogen		
		Benzopyrenes	
Anthracenes		Benzo[*a*]pyrene	Carcinogen
Anthracene	Suspected carcinogen	Benzo[*e*]pyrene	Carcinogen
9-Methylanthracene	Suspected carcinogen	3-Methylbenzo[*a*]pyrene	Suspected carcinogen
		Perylenes	
Phenanthrenes		Perylene	Suspected carcinogen
Phenanthrene	Toxic		
		Dibenzantracenes	
Pyrenes		Dibenz[*a,h*]anthracene	Carcinogen
Pyrene'	Carcinogen	Dibenz[*a,c*]anthracene	Suspected carcinogen
		Dibenz[*a,j*]anthracene	Suspected carcinogen
Fluoranthenes			
3-Methylfluoranthene	Suspected carcinogen	Dibensopyrenes	
Fluoranthene	Toxic	Dibenzo[*a,i*]pyrene	Carcinogen
		Dibenzo[*a,l*]pyrene	Suspected carcinogen
Indenopyrenes		Dibenzo[*a,e*]pyrene	Suspected carcinogen
Indeno[1,2,3-*cd*]pyrene	Suspected carcinogen	5-Methyldibenzo[*a,i*]pyrene	Suspected carcinogen
		Benzoperylenes	
Cholanthrenes		Benzo[*ghi*]perylene	Carcinogen
Cholanthrene	Suspected carcinogen		
3-Methylcholanthrene	Suspected carcinogen	Dibenzopentaphenes	
		Dibenzo[*h,rst*]pentaphene	Suspected carcinogen
Chrysenes			
Chrysene	Carcinogen	Dibenzoperylenes	
5,6-Dimethylchrysene	Suspected carcinogen	Peropyrene	Suspected carcinogen
5-Methylchrysene	Carcinogen	**Nitrogen heterocyclics**	
Benzanthracenes		Pyrroles	
Benz[*a*]anthracene	Carcinogen	Pyrrole	Toxic
6,8-Dimethylbenz[*a*]anthracene	Suspected carcinogen		
7,12-Dimethylbenz[*a*]anthracene	Suspected carcinogen	Morpholines	
8,12-Dimethylbenz[*a*]anthracene	Suspected carcinogen	Morpholine	Irritant
1-Methylbenz[*a*]anthracene	Suspected carcinogen	*N*-Ethylmorpholine	Irritant
2-Methylbenz[*a*]anthracene	Suspected carcinogen	Bismorpholinomethane	Carcinogen

(SOURCE: 106, p. 4a.a.1-4 to 4a.2.1-7)

TABLE C-3 (CONT'D)

Pyridines	
Pyridine	Irritant
α-Picoline	Irritant
3,4-Dihydroxypyridine	Carcinogen
Indoles	
Indole	Suspected carcinogen
Carbazoles	
Carbazole	Toxic
Benzocarbazoles	
Benzo[*a*]carbazole	Suspected carcinogen
Dibenzocarbazoles	
7*H*-Dibenzo[*c,g*]carbazole	Carcinogen
7*H*-Dibenzo[*a,i*]carbazole	Suspected carcinogen
7*H*-Dibenzo[*a,g*]carbazole	Suspected carcinogen
Quinolines	
Quinoline	Toxic
Isoquinoline	Toxic
Benzacrindines	
Benz[*c*]acridine	Suspected carcinogen
7,9-Dimethylbenz[*c*]acridine	Suspected carcinogen
7-Methylbenz[*c*]acridine	Carcinogen
Dibenzacridines	
Dibenz[*a,j*]acridine	Carcinogen
Phenazines	
Phenazines	Suspected carcinogen
Nonheterocyclic nitrogen compounds	
Nitriles	
Acetronitrile	Toxic
Acrylonitrile	Toxic
Aliphatic amines	
Piperidine	Toxic
Methylamine	Irritant
Ethylamine	Irritant
n-Propylamine	Irritant
n-Butylamine	Irritant
Triethylamine	Irritant
Ethylendediamine	Irritant
Cyclohexylamine	Irritant
Dicyclohexylamine	Irritant
Dimethylamine	Mutagenic
Allylamine	Irritant
Anides	
Acrylamide	Toxic
Acetamide	Carcinogen
N,N-Diethylacetamide	Suspected carcinogen
Acetylaminofluoranthene	Suspected carcinogen
Thioacetamide	Mutagenic
Acetanilide	Mutagenic
Aromatic amines	
o-Toluidine	Suspected carcinogen
m-Toluidine	Suspected carcinogen
β-Naphthylamine	Carcinogen
Diphenylamine	Suspected carcinogen
Benzidine	Suspected carcinogen
4-Amino-biphenyl	Suspected carcinogen
Aniline	Toxic
4,4-Methylenedianiline	Suspected carcinogen
Aminoazobenzene	Suspected carcinogen
Benzylamine	Irritant
p-Phenylenediamine	Irritant
Imines	
Etnylenimine	Toxic
Hydroxylamines	
N-Hydroxyaniline	Mutagenic
N-2-Naphthylhydroxylamine	Suspected carcinogen
Hydroxylamine	Mutagenic

TABLE C-3 (CONT'D)

Compound	Hazard
Hydrazines	
Hydrazine	Suspected carcinogen
1,3-Diethylhydrazine	Suspected carcinogen
Methylhydrazine	Suspected carcinogen
Hydroazobenzene	Suspected carcinogen
Semicarbazides	
Semicarbazide	Carcinogen
Azo compounds	
Azobenzene	Suspected carcinogen
Azoethene	Suspected carcinogen
Thioureas	
Thiourea	Suspected carcinogen
Mercaptans, aliphatic	
Methylmercaptan	Disagreeable odor
Ethylmercaptan	Disagreeable odor
Isopropylmercaptan	Disagreeable odor
a-Propylmercaptan	Disagreeable odor
2-Pentylmercaptan	Disagreeable odor
Isoamylmercaptan	Disagreeable odor
n-Amylmercaptan	Disagreeable odor
n-Hexylmercaptan	Disagreeable odor
β-Mercaptoethanol	Mutagenic
Mercaptans, aromatic	
Thiophenol	Disagreeable odor
Benzylmercaptan	Disagreeable odor
p-Thiocresol	Disagreeable odor
Thionaphthol	Disagreeable odor
Sulfonic acids	
Benzenesulfonic acid	Irritant
Methanesulfonic acid	Irritant
Sulfuric acid esters	
Dimethylsulfate	Suspected carcinogen
n-Propylmethanesulfonate	Mutagenic
Sulfoxides	
Dimethylsulfoxide (DMSO)	Suspected carcinogen
Sulfides	
Carbon disulfide	Toxic
Thiophenes	
Thiophene	Toxic
Benzene derivatives	
Polyaryls	
Biphenyl	Toxic
Double-bond conjugated benezenes	
Styrene	Toxic
Alkylbenezenes[a]	
Benzene	Suspected carcinogen
Phenols	
Phenol	Suspected carcinogen
o-Chlorophenol	Suspected carcinogen
2,4-Xylenol	Suspected carcinogen
2,5-Xylenol	Suspected carcinogen
2,6-Xylenol	Suspected carcinogen
3,4-Xylenol	Suspected carcinogen
3,5-Xylenol	Suspected carcinogen
o-Cresol	Toxic
m-Cresol	Toxic
p-Cresol	Toxic
1-Naphthol	Toxic
2-Naphthol	Toxic
Pyrogallol	Irritant
Hydroquinone	Irritant
Carboxylic acids	
Aliphatic acids	
Formic acid	Caustic
Acetic acid	Caustic
Propionic acid	Disagreeable odor
Butyric acid	Disagreeable odor
Valeric acid	Disagreeable odor
Caproic acid	Disagreeable odor

TABLE C-3 (CONCLUDED)

Acrylic acids	
Acrylic acid	Irritant
Methacrylic acid	Irritant
Carbamates	
Methylcarbamate	Mutagenic
Ethylcarbamate	Mutagenic
n-Butylcarbamate	Mutagenic
n-Propylcarbamate	Mutagenic
Lactones	
β-Propiolactone	Mutagenic
γ-Butyrolactone	Mutagenic
Amino benzoic acids	
Anthranilic acid	Suspected carcinogen
Aliphatic aldehydes	
Formaldehyde	Irritant
Acetaldehyde	Suspected carcinogen
Propionaldehyde	Irritant
Butyraldehyde	Irritant
Glyceraldehyde	Mutagenic
Aliphatic ketones	
Acetone	Irritant
Methylethylkatone	Irritant
Cyclohexanone	Carcinogen
α,β Unsaturated carbonyls	
Acrolein	Irritant
Crotonaldehyde	Irritant
Aromatic carbonyls	
Acetophenone	Irritant
Furfural	Irritant
Quinones	
Benzoquinone	Suspected carcinogen
Anthraquinone	Suspected carcinogen
2-Methylbenzoquinone	Suspected carcinogen
Other species	
Oxygen heterocyclics	
p-Dioxane	Suspected carcinogen
Coumarin	Suspected carcinogen
Alcohols	
Methanol	Toxic
Ethanol	Suspected carcinogen
Allyl alcohol	Irritant
Ethylene glycol	Suspected carcinogen
Cyclohexanol	Carcinogenic
Gaseous species	
Hydrogen cyanide	Toxic
Carbonyl sulfide	Toxic
Carbon monoxide	Toxic
1,3-Butadiene	Irritant

[a] Other major alkylbenzenes present as major constituents of their class are also significant.

TABLE C-4

POSSIBLE CONSTITUENTS OF GASIFIER OFF-GASES CATEGORIZED BY BOILING RANGE.

	Present in Gasification	Known Carcinogen
Boiling Point < 100°C		
Aliphatic Hydrocarbons:		
Amylene		
1,5-Butadiene		
Butylene		
Crotonylene		
Heptane		
Heptene		
Hexane		
Hexene		
Pentane		
Cyclic Hydrocarbons:		
Cyclohexadiene		
Cyclohexane		
Cyclohexene		
Cyclopentadiene		
Aromatic Hydrocarbon:		
Benzene	x	x
Oxygen-containing Compounds:		
Acetaldehyde		
Acetone		
Carbon monoxide	x	
Methyl ethyl ketone		
Nitrogen-containing Compounds:		
Acetonitrile		
Ammonia	x	
Hydrogen cyanide		
Nitrogen oxides		
Sulfur-containing Compounds:		
Carbon disulfide		
Carbonyl sulfide	x	
Diethyl sulfide		
Dimethyl sulfide		
Ethyl mercaptan		
Hydrogen sulfide	x	
Methyl mercaptan		
Sulfur dioxide		
Thiophene		
Boiling Point = 100°C to 150°C		
Aliphatic Hydrocarbon:		
Octane		
Cyclic Hydrocarbons:		
Dimethyl cyclohexane		
Methyl cyclohexane		
Nonaphthene		
Aromatic Hydrocarbons:		
Ethylbenzene		
Styrene		
Toluene	x	
o-Xylene		
m-Xylene		
p-Xylene		
Oxygen-containing Compounds:		
Acetic acid	x	
Propanoic acid	x	
Nitrogen-containing Compounds:		
2,6-Dimethyl pyridine		
2-Methylpyridine		
3-Methylpyridine		
4-Methylpyridine		
Pyridine		
Pyrrole		
Sulfur-containing Compounds:		
3-Methylthiophene	x	
Thioxene	x	

(SOURCE: 51, p. 157-161)

TABLE C-4 (CONT'D)

	Present in Gasification	Known Carcinogen
Boiling Point = 150°C to 200°C		
Aliphatic Hydrocarbon:		
Decane		
Cyclic Hydrocarbon:		
Dicyclopentadiene		
Aromatic Hydrocarbons:		
Cymene		
Durene		
o-Ethyltoluene		
m-Ethyltoluene		
p-Ethyltoluene		
Hemellitene		
Hydrindene		
Isodurene		
Isopropylbenzene		
Mesitylene		
n-Propylbenzene		
Pseudocumene		
Polynuclear Aromatic Hydrocarbons:		
2,7-Dimethylindene		
3,5-Dimethylindene		
Indene	x	
Oxygen-containing Compounds:		
n-Butanoic acid	x	
Coumarone		
o-Cresol	x	
Dimethylcoumarone		
n-Pentanoic acid	x	
Phenol	x	cocarcinogen
Nitrogen-containing Compounds:		
Aniline		
Benzonitrile		
Dimethylaniline		
2,3-Dimethylpyridine		
2,4-Dimethylpyridine		
2,5-Dimethylpyridine		
3,4-Dimethylpyridine		
Toluidine		
2,4,5-Trimethylpyridine		
2,4,6-Trimethylpyridine		

	Present in Gasification	Known Carcinogen
Boiling Point = 200°C to 250°C		
Aliphatic Hydrocarbon		
n-Dodecane		cocarcinogen
Polynuclear Aromatic Hydrocarbons:		
Cholanthrene		
Dihydronaphthalene		
4,6-Dimethylindene		
5,7-Dimethylindene		
1-Methylnaphthalene	x	
2-Methylnaphthalene	x	
Naphthalene	x	
Oxygen-containing Compounds:		
Acetophenone		
Benzoic acid		
m-Cresol	x	
p-Cresol	x	
2,2'-Dihydroxydiphenyl		
2,3-Dimethylphenol	x	
2,4-Dimethylphenol		
3,4-Dimethylphenol	x	
3,5-Dimethylphenol	x	
2,6-Dimethylphenol	x	
2,5-Dimethylphenol	x	
Dimethylcoumarone		
Durenol		
o-Ethylphenol	x	
m-Ethylphenol		
p-Ethylphenol		
n-Heptanoic acid	x	
Isopseudocumenol		
3-Methyl-5-ethylphenol		
Nitrogen-containing Compounds:		
Acetamide	x	
Isoquinoline		
2-Methylquinoline		
8-Methylquinoline		
Propionamide	x	
Quinoline		
1,2,3,4-Tetramethylpyridine		

TABLE C-4 (CONT'D)

	Present in Gasification	Known Carcinogen
Boiling Point = 200°C to 250°C (cont'd)		
Sulfur-containing Compounds:		
Diallylsulfide		
Dimethylbenzothiophene		
Methylbenzothiopnene		
2,3-Benzothiophene		
Boiling Point = 250°C to 300°C		
Aromatic Hydrocarbons:		
3,4'-Dimethyldiphenyl		
4,4'-Dimethyldiphenyl		
Diphenyl	x	
2-Methyldiphenyl		
3-Methyldiphenyl		
4-Methyldiphenyl		
Polynuclear Aromatic Hydrocarbons:		
Acenaphthylene	x	
Acenaphthene	x	
1,2-Cyclopentanonaphthalene		
1,2-Dimethylnaphthalene	x	
1,3-Dimethylnaphthalene	x	
1,5-Dimethylnaphthalene	x	
1,6-Dimethylnaphthalene	x	
1,7-Dimethylnaphthalene		
2,6-Dimethylnaphthalene	x	
2,7-Dimethylnaphthalene		
2,3-Dimethylnaphthalene	x	
1-Ethylnaphthalene		
2-Ethylnaphthalene		
Fluorene	x	
Oxygen-containing Compounds:		
Diphenylene oxide		
1-Methyldiphenylene oxide		
1-Naphthofurane		
2-Naphthofurane		
α-Naphthol	x	
β-Naphthol	x	
Resorcinol		

	Present in Gasification	Known Carcinogen
Boiling Point = 250°C to 300°C (cont'd)		
Nitrogen-containing Compounds:		
1,3-Dimethylisoquinoline		
2,8-Dimethylquinoline		
5,8-Dimethylquinoline		
Indole		
2-Methylindole		
3-Methylindole		
4-Methylindole		
5-Methylindole		
7-Methylindole		
1-Methylisoquinoline		
3-Methylisoquinoline		
3-Methylquinoline		
4-Methylquinoline		
5-Methylquinoline		
6-Methylquinoline		
7-Methylquinoline		
1-Naphthonitrile		
Boiling Point > 300°C		
Aliphatic Hydrocarbons:		
n-Heptadecane		
Nonadecane		
Polynuclear Aromatic Hydrocarbons:		
Anthracene		
1,2-Benzanthracene		x
2,3-Benzchrysene		
3,4-Benzfluorene		
Benz[*m,n,o*]fluoranthene		
2,3-Benzfluoranthene		x
3,4-Benzfluoranthene		
7,8-Benzfluoranthene		x
8,9-Benzfluoranthene		
1,2-Benzfluorene		
2,3-Benzfluorene		
1,2-Benznaphthacene		
1,2-Benzoanthracene		
1,2-Benzpentacene		

TABLE C-4 (CONT'D)

	Present in Gasification	Known Carcinogen
Boiling Point: > 300°C (cont'd)		
Polynuclear Aromatic Hydrocarbons (cont'd)		
1,12-Benzperylene		
3,4-Benzphenanthrene		x
1,2-Benzpicene		
1,2-Benzpyrene		x
4,5-Benzpyrene		x
Chrysene		x
Coronene		
1,2,3,4-Dibenzanthracene		
1,2,5,6-Dibenzanthracene		x
1,2,7,8-Dibenzanthracene		
1,2,6,7-Dibenzpyrene		x
1,2,7,8-Dibenzpyrene		x
3,4,8,9-Dibenzpyrene		
3,4,9,10-Dibenzpyrene		
3,4,8,9-Dibenztetraphene		
9,10-Dihydroanthracene	x	
5,12-Dihydronaphthacene		
9,10-Dimethylphenanthrene		
2,3-Dimethylanthracene		
2,7-Dimethylanthracene		
3,6-Dimethylphenanthrene		
2,2-Dinaphthyl		
Diphensuccindan		
Fluoranthene	x	cocarcinogen
1-Methylanthracene		
2-Methylanthracene		
9-Methylanthracene		
1-Methylchrysene		x
2-Methylchrysene		x
1-Methylfluorene		
3-Methylfluorene		
9-Methylfluorene		
1-Methylphenanthrene		
2-Methylphenanthrene		
3-Methylphenanthrene		
9-Methylphenanthrene		
1-Methylpyrene		cocarcinogen
3-Methylpyrene		cocarcinogen
4-Methylpyrene		cocarcinogen
Boiling Point: > 300°C (cont'd)		
Polynuclear Aromatic Hydrocarbons (cont'd)		
Naphthacene		
Naphthofluorene		
Naphtho-2',3'-1,2-anthracene		
Perylene		
Phenanthrene	x	
4,5-Phenanthrylene methane		
2,3-*o*-phenylene pyrene		
1-Phenylnaphthalene	x	x
2-Phenylnaphthalene	x	x
2-Phenylphenanthrene		
Picene		
Pyrene		cocarcinogen
1,2,3,4-Tetrahydroanthracene		
1,2,3,4-Tetrahydrofluoranthene		
2,3,6,7-Tetramethylnaphthalene		
1,3,7-Trimethylnaphthalene		
1,3,6-Trimethylnaphthalene		
1,2,8-Trimethylphenanthrene		
Triphenylene		
Truxene		
Oxygen-containing Compounds:		
Benzanthrone		
1,2-Benzdiphenylene oxide		
1,9-Benzoxanthene		
Brazan		
Dibenzocoumarone		
1,8-Dimethylphenylene oxide		
o,*o*'-Diphenol		
5-Diphenyl-γ-pyrone		
Hydroxyanthracenes		
4-Hydroxydiphenyl		
2-Hydroxyfluorene		
9-Hydroxy-4-methylfluorene		
p-Methoxybenzophenone		
Methyl brazans		
2-Methyldiphenylene oxide		
3-Methyldiphenylene oxide		

TABLE C-4 (CONCLUDED)

	Present in Gasification	Known Carcinogen
Boiling Point: > 300°C (cont'd)		
Oxygen-containing Compounds (cont'd)		
peri-Naphthoxanthene		
o(β-Naphthyl)phenol		
2-Phenanthrol		
4-Phenanthrol		
1-Phenylbenzanthrone		
p-Phenylphenol		
Tetramethyldiphenol		
Xanthene		
Nitrogen-containing Compounds:		
Acridine		
1-Azacarbazole		
2-Azafluoranthene		
13-Azafluoranthene		
4-Azafluorene		
1-Azapyrene		
1,2-Benzacridine		
3,4-Benzacridine		x
2,3-Benz-1-azacarbazole		
2,3-Benz-4-azafluorene		
1,2-Benzcarbazole		
2,3-Benzcarbazole		
3,4-Benzcarbazole		
2,3-Benzfluorenenitrile		
5,6-Benzquinoline		
7,8-Benzquinoline		
Carbazole		
1,2,5,6-Dibenzacridine		x
1,2,7,8-Dibenzacridine		x
9,10-Dihydroacridine		
Fluorene nitriles		
Hydroacridine		
Indeno[1,2,3-*c,d*]pyrene		x
4,5-Iminophenanthrene		
2-Methylacridine		
2-Methyl-5,6-benzquinole		
Boiling Point: > 300°C (cont'd)		
Nitrogen-containing Compounds (cont'd)		
2-Methylcarbazole		
3-Methylcarbazole		
2-Naphthonitrile		
1-Naphthylamine		
2-Naphthylamine		
1-oxo-1,2-dihydro-2-azapyrene		
Phenanthridene		
1,2,3,4-Tetrahydroacridine		
Sulfur-containing Compounds:		
1,2-Benzdiphenylene sulfide		
Benzo[*d,e,f*]dibenzothiophene		
4,5-Benzthionaphthene		
5,6-Benzthionaphthene		
6,7-Benzthionaphthene		
Benzylthiophene		
Dibenzothiophene		
2,3,5,6-Dibenzthionaphthene		
1,8-Dimethylphenylene sulfide		
Dinaphthothiophene		
Diphenylene sulfide		
Methyldibenzothiophene		
Methylthiophene		
Tetrahydrobenzothiophene		
Naphthobenzothiophene		

TABLE C-5

INDEX OF INDIVIDUAL TAR ACIDS FROM LOW-TEMPERATURE BITUMINOUS TAR BASED ON BOILING RANGE.

Compound	Boiling Range, °C[a]
Phenol	182
2-Methylphenol	190.8
2,6-Dimethylphenol	201
4-Methylphenol	202.1
3-Methylphenol	202.2
2-Ethylphenol	207
2,4-Dimethylphenol	210
2,5-Dimethylphenol	210
2-Ethyl-6-methylphenol	212-214
3-Ethylphenol	214
2-Isopropylphenol	214
2-Ethyl-4-methylphenol	216-218
2,3-Dimethylphenol	218
4-Ethylphenol	219
3,5-Dimethylphenol	219.5
2,3,6-Trimethylphenol	220
2-n-Propylphenol	220
4-Ethyl-2-methylphenol	222
2,4,6-Trimethylphenol	222
5-Ethyl-2-methylphenol	223
2-Ethyl-5-methylphenol	224.2
3,4-Dimethylphenol	225
3-Ethyl-2-methylphenol	227
2,4-Dimethyl-6-ethylphenol	227-228
3-n-Propylphenol	228
3-Isopropylphenol	228
2-Isopropyl-3-methylphenol	228.5
2-Isopropyl-4-methylphenol	228-229/763
4-Isopropylphenol	228-229/745
4-Ethyl-3-methylphenol	228-230
2-(Propen-1-yl)phenol	230-231
2,4,5-Trimethylphenol	232
4-n-Propylphenol	232.6
2-Methyl-6-n-propylphenol	233
3-Ethyl-5-methylphenol	233
2,3,5-Trimethylphenol	233

[a] All temperatures are measured at atmospheric pressure unless followed by a slash (/). The number to the right of the slash is the pressure at which the boiling ranges were obtained, in mm. Figures in parentheses are atmospheric boiling points estimated from reduced pressure data or from boiling-point data of isomers and homologues, in mm.

(SOURCE: 51, p. 162-164)

TABLE C-5 (CONT'D)

Compound	Boiling Range, °C[a]
2-Isopropyl-5-methylphenol	233.5
4-Isopropyl-2-methylphenol	230-235
3-Ethyl-4-methylphenol	234-235
2,3,4-Trimethylphenol	235-237
5-Isopropyl-2-methylphenol	236.8-237.4
4-Isopropyl-3-methylphenol	238
2,3-Dimethyl-6-ethylphenol	(240)166/100
4-Methyl-2-n-propylphenol	(241)121-123/18
3-Isopropyl-5-methylphenol	241
4-Indanol	245/764
Catechol	245
2,3,5,6-Tetramethylphenol	247-248
3,5-Diethylphenol	248
3-Methylcatechol	248
3,4,5-Trimethylphenol	248-249
3,5-Dimethyl-2-ethylphenol	(250)90-93/1
3,4-Dimethyl-6-ethylphenol	(250)
6-Methyl-4-indanol	(250)
7-Methyl-4-indanol	(250)
2,3,4,6-Tetramethylphenol	250
5-Indanol	255
2,6-Di-n-propylphenol	256/764
4-Methylcatechol	258
3,5-Dimethyl-2(propen-1-yl)phenol	(260)
7-Methyl-5-indanol	(260)
2,3,4,5-Tetramethylphenol	260
5,6,7,8-Tetrahydro-1-naphthol	264.5-265/705
2-Ethylresorcinol	(265)
Pentamethylphenol	267
4-Ethylresorcinol	(270)131/15
2-(Cyclopenten-2-yl)phenol	(270)133-135/12
2-(Cyclopenten-1-yl)phenol	(272)
2-Phenylphenol	275
5,6,7,8-Tetrahydro-2-naphthol	275-276
4-Methyl-5,6,7,8-tetrahydro-1-naphthol	(280)
4-Methyl-2-phenylphenol	(280)101-105/2
2-Cyclohexylphenol	282.5-283.5
2-(Cyclopenten-2-yl)-4-methylphenol	(284)105-108/1.3
2-Ethylhydroquinone	(285)
1-Naphthol	288.01
3-Methyl-5,6,7,8-tetrahydro-2-naphthol	(290)
4-Methyl-5,6,7,8-tetrahydro-2-naphthol	(290)
4-(Cyclopenten-1-yl)phenol	(293)
4-(Cyclopenten-2-yl)phenol	(293)114-117/1.5
2-Naphthol	294.85

TABLE C-6 (CONCLUDED)

Compound	Boiling Range, °C[a]
2-Methyl-1-naphthol	(295)
4-Cyclohexylphenol	293.5-295.5/752
4-Methyl-1-naphthol	(298)177-179/25
1 Methyl-2-naphthol	(300)
1,4-Dimethyl-5,6,7,8-tetrahydro-2-naphthol	(305)
5-Methyl-2-naphthol	(305)
3,4-Dimethyl-1-naphthol	(315)205-210/15
4-Phenylphenol	319
7-Ethyl-4-methyl-1-naphthol	(320)
3-Phenylphenol	325
5-Acenaphthenol	(332)221/40
4-Acenaphthenol	(338)
1-Fluorenol	(345)
2-Fluorenol	340-350
3-Fluorenol	(350)
8-Methyl-2-fluorenol	(355)

TABLE C-6

INDEX OF INDIVIDUAL TAR BASES FROM LOW-TEMPERATURE
BITUMINOUS TAR BASED ON BOILING RANGE.

Compound	Boiling Range, °C[a]
Pyridine	115.4
2-Methylpyridine	129.42
2,6-Dimethylpyridine	144.05
3-Methylpyridine	144.14
4-Methylpyridine	145.0
2-Ethylpyridine	148.6
2,5-Dimethylpyridine	157.01
2,4-Dimethylpyridine	158.40
2-Isopropylpyridine	158.9
2,3-Dimethylpyridine	161.16
2-Ethyl-6-methylpyridine	160-161.5
3-Ethylpyridine	162-165/762
2,4,5-Trimethylpyridine	165-168
4-Ethylpyridine	169.6-170/750
3,5-Dimethylpyridine	171.91
2,4,6-Trimethylpyridine	171-172
4-Isopropylpyridine	173
5-Ethyl-2-methylpyridine	174-176
2,3,6-Trimethylpyridine	176-178/759
3-Isopropylpyridine	177-178
3,4-Dimethylpyridine	179.13
4-Ethyl-2-methylpyridine	179-180
2,4-Dimethyl-6-ethylpyridine	181-182
2,3,5-Trimethylpyridine	182-183/739
Aniline	183.93
2,6-Dimethyl-4-ethylpyridine	186
2,4-Diethylpyridine	187-188
2,3,4-Trimethylpyridine	192-193
N,N-Dimethylaniline	192.5-193.5
3-Ethyl-4-Methylpyridine	195-196/753
N-Methylanine	196.1
2,3,5,6-Tetramethylpyridine	197-198
2,3-Cyclopentenopyridine	199.5
2-Methylaniline	200.3
4-Methylaniline	200.55
2,3,4,6-Tetramethylpyridine	203/750
3-Methylaniline	203.34

[a] All temperatures are measured at atmospheric pressure unless followed by a slash (/). The number to the right of the slash is the pressure at which the boiling ranges were obtained, in mm. Figures in parentheses are atmospheric boiling points estimated from reduced pressure data or from boiling-point data of isomers and homologues, in mm.

(SOURCE: 51, p. 165-167)

TABLE C-6 (CONT'D)

Compound	Boiling Range, °C[a]
N-Methyl-3-methylaniline	206-207
N-Methyl-2-methylaniline	207-208
N-Methyl-4-methylaniline	209-211/761
2,5-Dimethylaniline	213.5
2,6-Dimethylaniline	214/739
2-Ethylaniline	215-216/769
2,4-Dimethylaniline	215.8-216.0/728
3,5-Dimethylaniline	220-221
5,6,7,8-Tetrahydroquinoline	222.2
3,4-Dimethylaniline	226
Quinoline	237.1
2-Methylquinoline	245.8
8-Methylquinoline	247.3-248/751.3
2,8-Dimethylquinoline	252
3-Methylquinoline	252/735
7-Methylquinoline	251.5252.5
5-Methylquinoline	253-255/735
6-Methylquinoline	257.4-258/745
2,3-Dimethylquinoline	261/730
4-Methylquinoline	264.2
2,4-Dimethylquinoline	264-265
2,7-Dimethylquinoline	264-265
2,6-Dimethylquinoline	266-267
2,6,8-Trimethylquinoline	267.4/746
2-Phenylpyridine	268-269
3-Phenylpyridine	269-270/749
2,5,8-Trimethylquinoline	(273)143-145/15
4,6-Dimethylquinoline	273-274
4-Phenylpyridine	274-275
2,4,8-Trimethylquinoline	275.8/740
2,7,8-Trimethylquinoline	276.1/740
2,3,8-Trimethylquinoline	280/747
2,4,7-Trimethylquinoline	280-281
2,5,7-Trimethylquinoline	286.6/746
2,4,6-Trimethylquinoline	287/758
2-Naphthylamine	294
2,4,7,8-Tetramethylquinoline	295.5/742
1-Naphthylamine	300.8
2,4,5,8-Tetramethylquinoline	(310)168-172/12
N-Benzyl-2-methylaniline	(310)176/10
N-Benzyl-3-methylaniline	312
N-Benzyl-4-methylaniline	312-313
7,8-Benzoquinoline	335
6,7-Benzoquinoline	(345)200-205/14
2,3-Benzoquinoline	345-346

TABLE C-6 (CONCLUDED)

Compound	Boiling Range, °C[a]
3,4-Benzoquinoline	349/769
5,6-Benzoquinoline	350/721
2,4-Dimethylbenzo(*h*)quinoline	355
1,3-Dimethylbenzol(*f*)quinoline	(358)240/35
9-Methylacridine	359-360/740
2-Methylbenzo(*g*)quinoline	(360)
4-Methylbenzo(*g*)quinoline	(360)
2,3-Dimethylbenzo(*f*)quinoline	(360)
2,4-Dimethylbenzo(*g*)quinoline	(370)
3,4-Dimethylbenzo(*g*)quinoline	(370)

TABLE C-7

TYPICAL CATALYST AND CHEMICALS CONSUMPTION IN A LIQUEFACTION PROCESS

Item	Amount
Diatomaceous Earth Filter Precoat	20 tons/day
Monoethanolamine	3750 to 12,600
Cellulose, Asbestors, and Diatomaceous Earth	22 to 110 lb/day
Corrosion Inhibitor, A	3-1/4 to 6-1/2 gal/day
Antifoam	7-1/2 to 16 gal/day
Hydrogenation Catalyst	255,700 lb (3-yr life)
Sodium Hydroxide	340 lb/day
Active Carbon	50 to 100 lb/day
CO Shift Catalyst	2399 ft^3 (1-yr life)
Benfield Solution - K_2CO_3	986 lb/month
DEA	99 lb/month
V_2O_5	17 lb/month
Methanator Catalyst	140 ft^3 (3-yr life)
Zinc Oxide Pellets	71 ft^3 (3-yr life)
BSRP CoMo Catalyst	750 ft^3 (3-yr life)
Sulfur Recovery Catalyst	5200 (3-yr life)
Stretford Solution Chemical Makeup	$386/day
Corrosion Inhibitor, B	319 lb/day
Polymer Dispersant	319 lb/day
Sulfuric Acid	3209 lb/day
Chlorine	1766 lb/day
Phosphate Polymer Antifoam	383 lb/day
Hydrazine (oxygen scavenger)	2.7 lb/day
Lime	2072 lb/day
Aluminum Sulfate	1295 lb/day
Caustic soda	2135 lb/day

(SOURCE: 89, p. 171)

TABLE C-8

PRELIMINARY LISTING OF HIGH BTU GASIFICATION INPUT MATERIALS OTHER THAN COAL

ACID GAS CLEANUP MATERIALS

1. DIPA or di-isopropanol-amine; $[CH_3CH(OH)CH_2]_2NH$
2. MEA = mono-ethanol-amine
3. Alkazid-M = potassium salt of methyl amino propionic acid
4. Alkazid-DIK = potassium salt of dimethyl amino acetic acid
5. Potassium carbonate (K_2CO_3)
6. Benfield additives
7. Catacarb potassium salt solution
8. Catacarb non-toxic catalyst
9. DGA = diglycolamine; $HO\text{-}C_2H_4\text{-}O\text{-}C_2H_4\text{-}NH_2$
10. Propylene carbonate
11. Arsenic trioxide, As_2O_3
12. Glycine
13. Union Carbide proprietary molecular sieves or zeolites
    - 13a. Type 4A-LNG for CO_2
    - 13b. Several types of desulfurization
14. NMP = N-Methyl-2-Pyrrolidone
15. Methanol, CH_3OH
16. Dimethyl ether of polyethylene glycol (Selexol)
17. DEA = diethanolamine
18. Sulfolane = tetrahydrothiophene dioxide

(SOURCE: 63, p. 67-70)

TABLE C-8 (CONT'D)

19. Claus catalysts
    - 19a. Bauxite, balls or pellets
    - 19b. Alumina, balls or pellets (active)
    - 19c. Newer or more advanced catalysts

20. Sodium carbonate (Na_2CO_3)

21. Alkali arsenates
    - 21a. Sodium arsenates: Na_3AsO_3, $N2_3AsO_4$
    - 21b. Potassium arsenates: K_3AsO_3

22. Sodium meta vanadate ($NaVO_3$)

23. Sodium vanadate ($N_2V_4O_9$)

24. Sodium hydroxide (NaOH)

25. ADA = anthraquinone disulfonic acid

26. Redox catalyst = sodium 1,4-napthoquinone, 2-sulfonate

27. Sodium naptho - hydroquinone sulfonate

28. Beavon catalyst = cobalt moly I, cobalt moly II, catalyst S-501

29. Beavon alkalinebuffer solution

30. Cleanair solvent

31. Cleanair catalyst

32. Ammonia (NH_3)

33. SCOT Process catalyst - cobalt/molybdenum on alumina support

34. Activated carbon

35. Sulfuric acid (W-L SO_2 Recovery Process)

36. Anhydrous citric acid

37. MDEA = methyl-diethanol-amine; $(HOC_2H_4)_2NCH_3$

38. TEA = tri-ethanol-amine (supplanted by MDEA)

39. Octyl-phenoxyethanol (MDEA foam inhibitor)

TABLE C-8 (CONT'D)

40. Silicon antifoam agents (for MDEA)
41. Inhibitors for MEA; proprietary
42. Sodium polysulfide (Na_2S_{n+1}) - Stretford pretreatment for HCN
43. Iron oxides (FeO, Fe_3O_4)
44. Zinc oxide (ZnO)
45. Tributyl phosphate

DEHYDRATION PROCESSES

1. Molecular sieves, e.g., Union Carbide Type 4A
2. Silica gels and beads
3. Alumina
4. Glycols - diethylene, triethylene and tetraethylene

AFTERBURNERS

1. Natural gas
2. Fuel oils
3. Active noble metal catalysts on alumina supports
   ex: Pt/Al_2O_3

WATER POLLUTION CONTROL

1. Alum
2. Lime
3. Polyelectrolyte
4. Air
5. Monohydric phenols
6. Polyhydric phenols
7. Butyl acetate
8. Isopropyl ether
9. Activated carbon

TABLE C-8 (CONCLUDED)

10. Synthetic polymer
11. Phosphoric acid

SO_2 SCRUBBERS

1. Line (CaO)
2. Limestone ($CaCO_3$)
3. Sodium hydroxide (NaOH)
4. Sodium carbonate (Na_2CO_3)
5. Sodium sulfite (Na_2SO_3)
6. Sulfuric acid-dilute (H_2SO_4)
7. Ferric catalyst (Chiyoda 101 Process)
8. Magnesium oxide (MgO)
9. Ammonia (NH_3)
10. Copper oxide (CuO)

SHIFT REACTIONS

1. Iron-chromium catalysts

METHANATION

1. Iron oxide (Fe_3O_4)
2. Raney nickel catalyst
3. Thorium nickel catalyst
4. Other catalyst found to be effective, incl. Fe, Co, Ru, Rh, Pd, Os, Ir, Pt

TABLE C-9

SEMI-VOLATILE ORGANIC ACIDS IN PRODUCT WATER (-8L) FROM *IN SITU* COAL GASIFICATION (LERC, ERDA)[a]

Chromatographic Peak No.	Compound	Chromatographic Peak No.	Compound
1	methyl butyrate (tent.)	26	5-methyl-3-hexanol
1A	methyl pentanoate	27	2,2-dimethyl-3-pentanol
2	ethyl butyrate	28	heptanol isomer
3	$C_5H_{10}O_2$ (isomer)	31	methyl-*m*-toluate
3A	methyl-α-methyl butyrate	33	dimethyl methyl benzoate isomer
4	$C_7H_{14}O_2$ (isomer)	34	dimethyl methyl benzoate isomer
5	2-methyl-1,3-dioxane (tent.)	35	dimethyl methyl benzoate isomer
6	methyl hexanoate	36	phenol
8	$C_7H_{12}O$ (isomer)	37	dimethyl phenol isomer
9	2-methyl-2-propyl-1,3-dioxalane	38	dimethyl phenol isomer
10	methyl heptanoate	39	*o*-cresol
14	anisole	40	isopropyl phenol isomer
17	methyl octanoate	41	C_3-alkyl phenol isomer
17A	$C_8H_{12}O$ isomer	41A	ethyl phenol and cresol isomer
18	$C_8H_{12}O$ isomer and $C_9H_{16}O$ isomer	41B	C_3-alkyl phenol isomer
20	methyl nonanoate	42	xylenol
21	trans-decalin	43	cresol and C_3-alkyl phenol
22	cis-decalin	44	dimethyl phenol
23	methyl decanoate	45	ethyl phenol isomer

(SOURCE: 99, p. 81-82)

TABLE C-9 (CONCLUDED)

Chromatographic Peak No.	Compound	Chromatographic Peak No.	Compound
24	phenyl acetate	45A	ethyl phenol isomer
25	methyl benzoate	46	dimethyl phenol isomer

[a] Sample extract treated with diazomethane.

TABLE C-10

COMPOSITION AND GROSS HEAT CONTENT OF PRODUCED GAS[a]

Identification														
Date, 1968	10/14	10/14	10/15		10/16		10/17		10/28		10/31	11/11		11/21	
Cumulative air injected in I-1, million ft^3	0.07	0.14	0.17		0.20		0.23		1.37		1.97	8.85		19.46	
Well number	S-1	S-1	S-1	S-2	S-1	S-2	S-1	S-2	S-1	S-2	S-1	S-1	S-2	S-1	S-2
Component, vol %															
Benzene	0.14	0.00	0.12	0.00	0.24	0.00	0.24	0.00	0.19	0.00	0.12	0.31	0.00	1.62	0.17
Hydrogen	13.23	11.16	8.66	8.74	8.74	8.48	9.61	8.56	9.40	9.82	9.03	15.63	11.8	18.61	10.93
Methane	24.21	16.22	19.52	17.16	25.53	28.59	20.59	27.42	14.75	15.6	13.25	17.56	4.03	23.62	6.71
Ethane	1.32	0.71	0.95	0.64	1.26	0.81	0.89	0.96	0.68	0.78	0.63	0.52	0.25	0.86	0.31
Propane	0.27	0.17	0.26	0.18	0.27	0.17	0.22	0.25	0.21	0.14	0.22	0.14	0.16	0.22	0.17
Butanes +	0.28	0.35	0.11	0.14	0.56	0.16	0.38	0.23	0.11	0.75	0.14	0.00	0.00	0.47	0.00
Carbon monoxide	7.62	8.33	6.51	7.66	4.16	4.84	6.32	5.47	7.05	7.16	7.38	15.13	13.26	19.8	6.93
Carbon dioxide	10.43	11.76	12.85	1.94	13.22	3.67	12.99	5.04	14.34	12.83	15.02	7.43	12.88	13.65	19.08
Nitrogen	41.86	50.65	50.44	62.7	45.55	52.55	48.15	51.38	52.36	52.25	53.28	41.38	56.44	15.69	59.89
Argon	0.54	0.64	0.53	0.83	0.53	0.73	0.61	0.68	0.65	0.66	0.67	0.53	0.74	0.19	0.72
Oxygen	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.11	0.15	0.00	0.00	0.00	0.00
Ammonia	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.27	0.20	0.00	0.00
Hydrogen sulfide	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.04	0.14	2.64	0.00
Other sulfur compounds	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00
Heat content, Btu/ft^3	355	253	274	244	356	351	301	350	229	257	212	299	130	465	140

[a] Water-vapor-free.

(SOURCE: 15, p. 3-120)

APPENDIX D

LEGISLATION APPLICABLE TO COAL CONVERSION FACILITIES

Appendix D gives a partial listing of Federal legislation which may affect the development and siting of coal conversion facilities. State and local regulations may dictate more stringent requirements than Federal regulations. Siting of a major coal conversion facility must be approached on a case-by-case basis to determine all applicable regulations and permit requirements. At the present time it is impossible to predict how stringent or how comprehensive environmental regulations of commercial coal conversion systems will be. However, prior to commercialization, such legislation and regulation will be needed at federal, state, and local levels.

FEDERAL ENVIRONMENTAL LEGISLATION APPLICABLE TO COAL CONVERSION

Legislation	Applicability to Coal Conversion
o National Environmental Policy Act of 1969 (NEPA) PL 91-190	o Environmental Impact Statement (EIS's) must be prepared for all major Federal actions significantly affecting the quality of the human environment.
o Non-nuclear Energy Researcg abd Development Act of 1974 (Section 13) PL 93-577	o Water availability assessments are required for demonstration and commercial plants; assessments are reviewed by the Water Resources Council (WRC).
o Clean Air Act as amended PL 91-604 As amended by PL 92-157 PL 93-15 PL 93-319	o Ambient air quality standards have been set for SO_2, TSP, NO_2, CO, HC, and O_3; more are being considered. o New Source Performance Standards (NSPS) apply to coal-fired boilers and regulate SO_2, NO_2 and particulates. Lower emission levels are being considered, as are regulations for small particulates. Stricter standards specific to coal lique faction may be forthcoming. New Source Performance Standards have been developed for first generation Lurgi high-Btu gasification processes. NSPS for low-Btu and second generation high-Btu gasification processes will be developed during FY 1978-1979. o Standards for hazardous air pollutants limit mercury, beryllium, and lead emissions. Currently limits coal types that can be used for demonstration plants.

(Source: 26, 37, 28)

	o NSPS and regulations for the prevention of significant deterioration may affect plant siting; nonattainment criteria may be extended to NO_3 which could affect plant siting. o Best Available Control Technology (BACT) may be required for coal conversion demonstration facilities.
o Federal Water Pollution Control Act Amendments of 1972 PL 92-500	o National Pollutant Discharge Elimination System (NPDES) permits are required to control wastewater discharges. o Since effluent guidelines have not been developed for most fossil energy technologies, permit requirements are determined on a case-by-case basis to meet State plans. o A "No Discharge" goal has been set for 1985.
o Resource Conservation and Recovery Act of 1976 PL 89-272	o Solid waste disposal must comply with most stringent air and water standards; monitoring is required. State or EPA permits required for all landfills by 1 April 1988. o New regulations will be developed in 1-2 years for a Federal hazardous waste handling permit system and state programs for non-hazardous solid wastes. All hazardous wastes will be classified.
o Toxic Substances Control Act (TOSCA) PL 94-469	o Disposal of specific materials (e.g. nickel catalyst) used in conversion processes may be regulated.

o Safe Drinking Water Act PL 93-523	o Wastewater discharges may require additional treatment for heavy metals or organic waste if they impact drinking water supplies. Proposed EPA Guidelines will regulate down well injection of water and waste water and thus may significantly impact plans to reinject water and steam which accompanies product.
o Noise Control Act of 1972 PL 92-574	o To protect health and welfare ambient noise levels are recommended; they may become standards for facilities regulated by State and local governments.
o Occupational Safety and Health Act (OSHA) PL 91-596	o Health and safety regulations must be met for workers in coal conversion Noise levels for compressors, pumps, etc. are limited and must be controlled. Health regulations will be forthcoming.
o Coastal Zone Management Act of 1972 PL 92-583	o State coastal zone management plans developed with Federal financial assistance may affect plant siting and design.
o Marine Protection, Research and Sanctuaries Act of 1972 PL 92-532	o Permits are required for activities in in wetland areas, which may restrict conversion facility siting.
o Rivers and Harbors Act 33USC 401-413	o Permits are required for dredge and fill activities in navigable waters, which may affect facilities siting. o Projects must be integrated with flood control, river, and dam projects.
o National Historic Preservation Act of 1966 PL 89-665	o Federally financed, assisted, or permitted projects cannot impact important historic or cultural sites unless no alternatives exist.

o Endangered Species Act PL 93-205	o Identification of endangered aquatic and terrestrial species at a potential construction site is required, which may affect facility siting.
o Fish and Wildlife Coordination Act PL 85-624	o Any project requiring modification of of bodies of water must be reviewed to prevent loss or damage to fish and wildlife.
o Wild and Scenic Rivers Act PL 90-542	o Projects must not degrade the quality of wild and scenic rivers.
o Energy Reorganization Act of 1974 PL 93-438	o ERDA is required to ensure environmental acceptability of the fossil energy and other technologies under development

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